National Energy Board

CANADIAN ENERGY

Supply and Demand 1987-2005

September 1988

National Energy Board
CANADIAN ENERGY
Supply and Demand 1987-2005
September 1988

Page 90	Table 5-7. Footnote [a] should read: "Takes into account capacity purchased from Churchill Falls of 4700 megawatts in 1986 and in 1990, and 4400 megawatts in 2005".
Page 100	Second sentence of third paragraph of Section 5.5 should read: "140" gigawatts rather than "139" gigawatts.
Page 100	Table 5-16. Units shown for "Generating Capacity" should read: "(MW)" and not "(GW)".
Page 229	Appendix Table A4-3. Footnote [b] should read: "12.1 GJ/MW.h" rather than "12 GJ/MWh".
Page 273	Appendix Table A4-8. The heading should read: "British Columbia and Territories".
Page 355	Appendix Table A7-10. The second last line should read: "...decline of the RLI".
Page 356	Appendix Table A7-11. The second last line should read: "...decline of the RLI".
Page 353	Appendix Table A7-8. Footnote [a] should read "... waterflood and thermal categories".
Page 367	Appendix Table A7-16. The heading should read: "British Columbia and Territories".
Page 389	Appendix Table A9-1. The EMR report number under "Source" should read: "ER 79-9".
Pages 395 to 413	Appendix Table A10-1. The column titled "Natural Gas" should read "Natural Gas (j)", and footnote (j) should read: "...with Table A4-3 and A4-4".

In Appendix Table A10-1, in the columns titled "Nuclear" and "Total", the numbers for "Steam Production" under the heading "Conversion Losses - Domestic" are incorrectly not reflected in subsequent totals. The correct numbers are as follows:

	Page																		
"Nuclear" Column	395	396	397	398	399	400	401	402	403	404	405	406	407	408	409	410	411	412	413
Total Conversion Losses	309	*	617	723	723	770	771	788	794	797	795	838	842	936	945	912	910	877	984
Domestic Demand for Primary Energy	456	*	882	1026	1026	1091	1094	1116	1126	1127	1130	1188	1204	1314	1328	1284	1294	1247	1406
Total Primary Demand, Primary Domestic Production, and Total Primary Supply	456	*	910	1058	1059	1134	1135	1165	1168	1164	1167	1241	1244	1359	1362	1299	1303	1251	1413
"Total" Column																			
Total Conversion Losses	839	*	1275	1279	1291	1305	1339	1310	1400	1379	1481	1438	1556	1593	1737	1622	1831	1767	2017
Domestic Demand for Primary Energy	8456	*	8890	9074	9108	9185	9313	9249	9575	9469	9854	9672	10133	10225	10898	10780	11724	11432	12586
Total Primary Demand	10925	*	12926	13689	13802	13773	14105	13830	14524	14004	14827	14118	15104	14299	15928	14755	16872	15418	17771
Primary Domestic Production	9091	*	11364	12028	12186	12163	12497	12227	12880	12273	13097	12379	13352	12439	14270	12556	15125	12798	15825
Total Primary Supply	10911	*	13004	13699	13807	13867	14155	13933	14599	14056	14901	14203	15170	14698	16050	14998	16992	15649	17871

*No changes to page 396.

CANADIAN ENERGY
SUPPLY AND DEMAND 1987-2005

NATIONAL ENERGY BOARD
SEPTEMBER, 1988

Cat. No. NE 23-15/1988E
ISBN 0-662-164444-X

This report is published separately in both official languages.

Ce rapport est publié séparément dans les deux langues officielles.

Copies are available on request from:

Regulatory Support Office
National Energy Board
473 Albert Street
Ottawa, Canada
K1A 0E5
(613) 998-7204

Exemplaires disponibles auprès du:

Bureau du soutien de la réglementation
Office national de l'énergie
473, rue Albert
Ottawa (Canada)
K1A 0E5
(613) 998-7204

Printed in Canada

Imprimé au Canada

Table of Contents

Foreword

The National Energy Board (NEB) was created by an Act of Parliament in 1959. The Board's regulatory powers under the National Energy Board Act include the licensing of the export of oil, gas and electricity, the issuance of certificates of public convenience and necessity for interprovincial and international pipelines and international power lines and the setting of just and reasonable tolls for pipelines under federal jurisdiction. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities, including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

Since its inception the Board has prepared and maintained projections of energy supply and requirements and has from time to time published reports on them after obtaining the views of interested parties. The latest of these reports was issued in the fall of 1986. It was prepared by Board staff without the involvement of Board members in a formal hearing process. In preparing the October 1986 Report, Board staff made use of an informal consultation process, the objective being to benefit from the advice of interested parties at reduced cost to themselves and to the Board. Although anyone wishing to submit information was welcome to do so, the Board did not request formal submissions. Board staff prepared preliminary assumptions and results; consulted with provincial governments, industry and other interested parties; and in light of these consultations developed the projections used.

Since October 1986 the near-term outlook for energy markets has been evolving with changing perceptions of energy prices, economic activity, and the availability of energy supplies. Government policies have also evolved at both the federal and provincial levels in Canada, and in the United States, the major market for our exports of energy. Both countries have changed the regulation of energy markets in a manner that will give the market-place a predominant role in determining supply, demand and prices.

In December 1987 the Board announced that its staff would update the October 1986 Report. The Board stressed that this updating would be separate and distinct from any of the Board's regulatory proceedings.

For this report, two rounds of consultations were held. The first concerned methodology and assumptions as to world oil prices and economic growth; the second, preliminary projections. These consultations encompassed all provincial governments and a wide variety of industry and other interested parties, including utilities, associations, companies, research institutes, and various federal government departments or agencies.

We thank all those who generously gave of their time and expertise to this endeavour; their input was most useful.

This report provides detailed information on the assumptions, methodology and results of the analysis of the supply and demand for energy in Canada. The interpretations and conclusions presented are, of course, those of Board staff. Copies of this report or of a companion summary report can be obtained by contacting the Board in Ottawa at (613) 998-7204 or in Calgary at (403) 292-6700. Any questions should be directed to the persons listed in Appendix 11.

List of Tables in Text

List of Figures

Chapter 1

Introduction

At the time of the publication of the Board report *Canadian Energy Supply and Demand 1985-2005*, October, 1986 (the October 1986 Report) world energy markets were characterized by excess supply of oil and natural gas and oil prices had declined dramatically in early 1986. While they have rebounded from the low levels of the first quarter of that year, oil prices remain in a range of $US 15 to 18 reflecting the continuing oversupply of crude oil in the world market.

Prices are being determined more by the actions of individual buyers and sellers in world markets than by the concerted action of producing countries. It now appears unlikely that OPEC will be able to restrain production to the extent needed to sustain higher prices given the large excess of oil supply. It seems increasingly clear that oil prices will rise mainly in response to growing world demand and its impact on the cost of non-OPEC oil supply over time. This in turn raises questions about the appropriate treatment in a study of this kind of the relationship between oil prices and economic growth.

North American natural gas markets are evolving in response to a less regulated, more market oriented, environment. In 1986 the U.S. government and regulatory authorities were proceeding to allow natural gas prices to be determined by supply and demand and the Federal Energy Regulatory Commission (FERC) was attempting to reform its regulation of pipelines to provide more open access.

After having increased in 1985 in response to the implementation of negotiated export prices, Canadian natural gas exports declined in 1986. This decline proved to be temporary; it was related, in large measure, to a substantial restructuring of U.S. gas markets to which Canadian exporters had to adapt, and to problems they faced in obtaining access to U.S. pipelines.

In Canada the Agreement on Natural Gas Markets and Prices had been signed in October 1985 but it was not yet clear when we did our analysis for the October 1986 Report how the market would adapt to the new environment, or how rapidly any such adaptation would occur.

In the past two years there has been much progress in the U.S. in achieving more open access to all buyers and sellers on the major interstate gas pipelines. Canadian exporters have adapted to the changing structure of the U.S. market; a greater proportion of Canadian gas exports is being sold directly to local distributors and end users. This has been facilitated by the increasing availability of transportation service on the major U.S. pipelines to which Canadian transmission lines are connected.

In response, Canadian exports of natural gas rebounded in 1987 and continue to grow in 1988, perhaps resulting in a new volume record. Canadian exporters have been able to take advantage of their favourable competitive position.

The U.S. gas surplus is declining, albeit slowly, and natural gas prices are still depressed.

The Canadian gas market also continues to be characterized by a large excess supply. It has, however, adapted rapidly to the implementation of negotiated pricing; there has been an appreciable increase in sales directly from producers to end users at negotiated prices. Like the U.S., the Canadian market is in transition; the ability of market transactions to influence prices is limited by the existence of long-term contracts between major distributors and TransCanada PipeLines Limited, by pipeline regulation which has the effect of restricting the ability of these distributors to substitute cheaper for more expensive gas, and by removal policies of the major producing province. Nonetheless, prices are responding increasingly to market forces.

The basic policy thrust of governments in both Canada and the U.S. remains that of allowing markets to set prices. Since completing our 1986 report there have been further developments in this direction in Canada. The NEB revised its natural gas export licensing procedures, allowing increased play for market forces to determine exports, while preserving the Board's responsibility to satisfy itself that exports are surplus to

Canadian requirements and are in the public interest.

These developments in Canadian and U.S. natural gas markets raise questions about the proper treatment of Canadian gas exports in our study and about the treatment of natural gas price determination in Canada. In this report we make major changes to our previous practices in both of these respects.

There is increasing concern about the environmental implications of burning fossil fuels. This concern has been highlighted internationally by publication of the Brundtland report[1] and in Canada by the Energy Options report.[2] Though the concern relates to fossil fuels used for all purposes, it has tended to focus on fossil fuel use in generating electricity.

Environmental concerns about electricity production make fossil fuel options costlier and less acceptable than in the past, at a time when there is growing concern about the adequacy of planned supply to meet electricity demand in some regions of Canada and the U.S.

Within Canada, the debate about future sources of electricity and their environmental consequences has been most pronounced in Ontario where the choice is between building more nuclear or coal plants or of purchasing electricity from its hydro-rich neighbours. All provincial governments are, however, seeking means of meeting their electricity needs in ways which may be more environmentally benign, some by encouraging the production of power by small independent producers, others by investigating the possibility of paying would-be consumers to reduce demand.

All of these developments have led us to rethink the way we conduct our analysis for this report. The main issues we must address in this environment are:

- by what means and what time will today's North American gas and world oil surpluses be eroded and markets brought into closer supply/demand balance,
- what factors will determine the future path of oil and natural gas prices, and what are these prices likely to be,
- what levels of natural gas domestic consumption and exports may be envisaged, if largely determined by operation of market forces,
- how would the natural gas market respond to a prospect of protracted low world oil prices, and
- what pricing, demand management, supply planning and trading approaches will our electrical utilities adopt in order to balance future demand and supply for electricity in an environmentally acceptable manner?

Our general approach is similar to the one we followed in 1986; we continue to use an underlying framework in which we define lower and higher sustainable paths of oil prices. In 1986 we said:

"The approach we have selected for this study is to define what may be described as lower and higher sustainable paths of oil prices. The factors giving rise to either a lower or a higher sustainable price path are demand growth (which in turn depends on economic variables and the efficiency of energy use), evolution and cost of non-OPEC supply, the market share falling to the middle-Eastern OPEC countries, and the consequent leverage they have to achieve price increases without substantially eroding their market share. Uncertainty about these factors means that there could be a wider band of sustainable price paths than the one we have adopted.

The definition of the lower and higher price paths does not mean that oil prices will remain on either one of these paths year after year. The oil price will most likely fluctuate above or below each of these paths in any year, but it is not possible to forecast these fluctuations. The meaning of these two scenarios is that each is a qualitatively different long-term view emerging from different behavioural assumptions sustaining either relatively lower or higher prices. Moreover, it is possible that the actual path could be a composite of the two projections, for example close to the low path in the earlier years, drifting up over time toward the higher path by the end of the study period.

Having established this range for world oil prices, the thrust of our study is to analyze what difference it would make to demand and supply for energy in Canada if experience validated either the higher or the lower price path."[3]

---

1. *Our Common Future*, United Nations World Commission on Environment and Development, Oxford University Press, 1987.
2. *Energy and Canadians into the 21st Century: A Report on the Energy Options Process*; Energy, Mines and Resources Canada, 1988.
3. *Canadian Energy Supply and Demand 1985-2005*, October, 1986, p. 3.

In 1986 we first developed our two world oil price scenarios on the basis of alternative views about international supply and demand for oil. We then constructed Canadian economic growth scenarios which differed only because of the impact on growth of higher or lower oil prices. In that report, high oil prices had a small negative impact on Canadian economic growth, while low oil prices had a slight positive one.

In this report we have taken a broader view of the relationship between oil prices and economic growth. Our approach is based on the assumption that, given the present state of the world oil market, characterized as it is by substantial excess supply, the extent to which oil prices can increase on a sustained basis depends largely upon how much international demand grows, and consequently what effect this demand growth has on the cost of non-OPEC oil supply. In this framework, Canadian economic growth will be influenced more by the world economic environment in general, of which oil prices are a part, than by the level of oil prices alone.

This is not to deny that OPEC behaviour can influence oil prices or that, other things equal, oil prices influence the rate of economic growth in oil importing countries; the evidence is clear that abrupt and large price shocks have influenced economic growth and could do so again. We argue simply that, absent special circumstances causing price shocks and given current conditions in world oil markets, the balance of probabilities is that prices in the next few years will be driven more by demand conditions, which in turn are powerfully affected by economic growth, than by supply factors.

In the longer run, supply will exert an increasingly important influence; oil prices will be higher the lower or costlier are supplies of oil from non-OPEC countries, and they will be higher the greater is the extent to which OPEC is able to control supply from its member countries. These circumstances are more pronounced in a higher, rather than a lower oil demand environment.

In our framework, higher demand for oil results primarily from higher economic growth and lower oil demand from lower growth. Thus high economic growth and high oil demand resulting in high oil prices constitute one scenario; and lower economic growth along with lower oil demand resulting in lower oil prices the other scenario.

"...high economic growth and high oil demand resulting in high oil prices constitute one scenario; and lower economic growth along with lower oil demand resulting in lower oil prices the other scenario".

This is not to argue that higher oil prices lead to higher oil demand; they do not:

- As oil prices increase, consumers respond by using less oil. Conversely, as oil prices fall, demand for oil could increase.
- Increasing oil prices can also have the effect of reducing economic growth in countries which are net oil importers, constraining future oil demand growth. We believe that this impact is temporary, and that there are more preponderant factors affecting economic growth, especially over a long period of time.

Price-induced impacts on oil demand and on economic performance would be larger with abrupt and large oil price shocks than if oil price changes were more gradual. Our scenarios do not portray oil price shocks because we do not think them predictable in any reliable way. Therefore, we believe that our basic line of causation, which proceeds from economic growth of the world economy to world oil demand and through world demand to oil prices, results in sustainable scenarios. We do, however, project oil demand to grow by less than economic growth rates, to account for the impact of increasing oil prices as well as ongoing structural changes in OECD countries which moderate the growth of oil demand. The extent of oil price growth depends both on the extent of demand growth and on the availability of oil from OPEC and non-OPEC sources at different prices to meet these demands.

We develop two scenarios because we perceive considerable uncertainty about whether international economic performance will be higher or lower. Much depends upon the policies adopted and the character of international co-ordination for resolving the large trade and fiscal imbalances and indebtedness of major countries.

Our scenarios are not forecasts of what will happen. Each scenario is an alternative view of what we would expect to happen under different assumptions about

economic growth and world oil prices.

We have implemented major changes in our analysis of natural gas markets in this report; these relate to our treatment of gas exports and to the determination of prices for Canadian natural gas.

In previous reports we projected natural gas exports only in the context of existing licence authorizations, and we did not allow for any exports beyond the horizon of existing licence authorizations. Since 1986, regulation of natural gas exports has been changed so that they are likely to be determined to a greater extent by natural gas market conditions - supply, demand and prices - in North America than they had previously been. Accordingly we have assessed the prospects for natural gas exports on the basis of an analysis of the competitiveness of Canadian natural gas in U.S. regional markets over our study period and we have taken account of how exports affect gas supply, demand and prices in Canada.

With respect to the domestic natural gas market, when we were preparing the October 1986 Report regulatory changes had just begun and it was not yet clear how natural gas prices in Canada would be determined. In light of this we chose to adopt the working assumption that the price of natural gas in Canada would be linked to the price of heavy fuel oil. In doing this we recognized that oil prices would have an important influence on natural gas prices. We also recognized, however, that there could be features unique to the natural gas markets which could cause the price of gas to depart from parity with oil prices.

Indeed the results of the analysis in the October 1986 Report suggested that a fixed link between natural gas and oil prices was inappropriate. Our analysis suggested that, were natural gas prices to be linked in a fixed relationship to oil prices, the demand for natural gas in Canada would likely exceed its supply during the course of our study period, particularly where oil prices were relatively low. In other words, our analysis suggested that the supply conditions of natural gas were such that linking its price to the oil price would be unlikely to lead to a sustainable supply/demand balance in the natural gas market. We acknowledged in 1986 that excess demand for gas could not persist and that further adjustment was necessary.

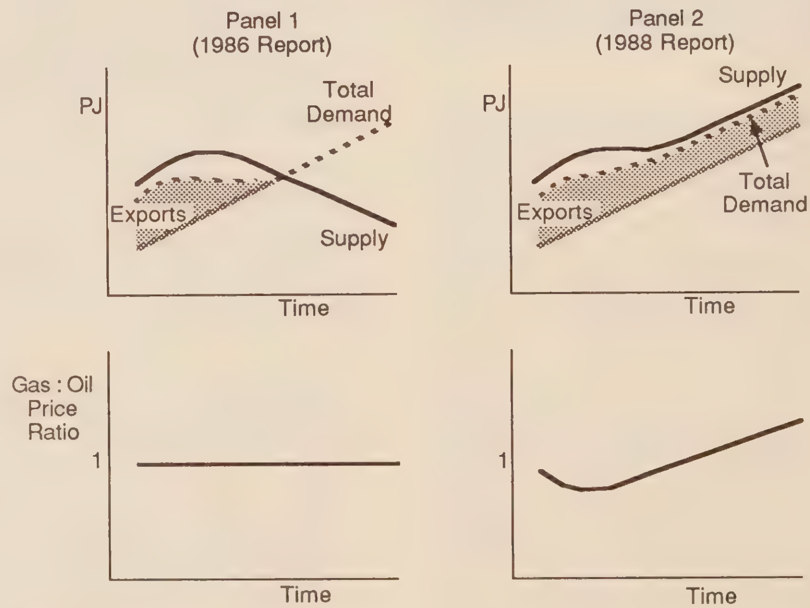
Drawing on those results and recent market experience, we conduct our analysis in this report by allowing natural gas prices to change as required in order to maintain equality between supply and demand (domestic and export) for Canadian natural gas, recognizing that this may result in natural gas prices rising or falling over time relative to oil prices.

The differences in the nature of the results of our analysis in the two reports are illustrated in a stylized way in Figure 1-1. Panel 1 portrays the results we obtained in the 1986 report. The gas/oil price ratio is held constant and, eventually, demand exceeds supply, an unsustainable situation.

In this report we allow natural gas prices to fluctuate independently of oil prices in order to first achieve and then preserve balance in natural gas markets. The results are qualitatively as shown in Panel 2. When the existing oversupply of gas disappears, supply remains roughly equal to demand, but this

Figure 1-1

Natural Gas Market



involves a gradual rise in the price of natural gas relative to that of oil, a rise which is much more pronounced with low oil prices than with higher ones. The analytical framework which we have adopted in this report has the major virtue of allowing us to analyze the implications for gas prices and the size of the Canadian natural gas industry of changes in domestic demand, export demand or supply availability and cost.

Low oil prices pose a particular problem for the competitiveness of natural gas in industrial and commercial facilities which have or could install multi-fuel handling capability, allowing them to switch out of gas into oil without much difficulty. The main issue which the gas industry would face in this situation is whether gas supply costs and pricing arrangements would adjust in order to preserve this market, or whether the size of the gas market would shrink substantially and the cost of serving remaining customers increase. We address this issue in our analysis of natural gas pricing in the low case, which is characterized by low economic growth and low oil prices.

In the October 1986 Report we assumed that electricity prices would remain constant in real terms, based on discussions with the utilities. We do the same in this report, even though some utilities could allow prices to fall over the next few years and increase thereafter. However, in this report we are better able to assess the difference in pricing between the "constant real" assumption, and a rigorous "cost of service" or "financial target" basis of electricity price determination. Moreover, unlike 1986, in this report we incorporate demand management measures for those provinces in which utilities indicate firm plans to implement them, and we discuss alternative supply arrangements which could be adopted to meet load growth such as more interprovincial trade in electricity and greater use of the production of independent power producers.

The energy demand profile outlined in this report includes our estimates of natural gas, oil, NGL, coal, and electricity exports including, in the case of natural gas and electricity, potential exports not yet authorized by the Board. As is the case with all estimates in this report, our estimates of energy exports are, of course, independent of and without prejudice to Board consideration of future energy export or facilities applications.

Plan of Report

Chapter 2 describes economic growth and oil price assumptions underlying the demand and supply projections for each of the low and high cases.

Chapter 3 explains the methods used to project natural gas and electricity prices and sets out the resulting price projections.

Total end use energy demand is examined in Chapter 4 by consuming sector, by region of Canada and by fuel. Hydrocarbon demand for non-energy use (mainly petrochemical feedstock) is also discussed. Fuels are needed to provide end use energy, for example, electricity generated in thermal power plants requires coal, oil, natural gas or uranium for its production. When these requirements are added to end use demand, the result is "primary energy demand", also examined in Chapter 4.

In subsequent chapters the report examines the ability of domestic energy sources to satisfy projected domestic demand and exports.

Chapter 5 discusses electricity generating capacity and electrical energy production by region required to satisfy projected domestic and export demand. It also assesses an alternative scenario for electricity generation based on increased interprovincial trade, and concludes with our projection of primary energy used to generate electricity for domestic and export markets.

Chapter 6 discusses natural gas resources and established reserves, reserves additions from conventional areas, supply from frontier areas, and productive capacity. It then examines the factors affecting natural gas exports and sets out our projections for exports and how they were derived.

Chapter 7 examines crude oil supply, beginning with resources and established reserves. It then discusses the prospects for reserves additions from enhanced oil recovery and drilling in conventional areas, synthetic crude and bitumen, pentanes plus and supply from frontier areas. Total oil supply projections then follow. Next, petroleum product balances are examined along with the implications for refinery feedstock requirements. Supply and demand profiles are set out, first for each of light and heavy crude oil and then for each of crude oil and petroleum products. The chapter concludes with comments on the implications for oil pipelines of projected oil supply and demand.

Chapter 8 examines the prospects for supply of natural gas liquids from gas plants in conventional areas, oil refineries, and frontier projects. It then reviews the domestic demand for natural gas liquids and the prospects for exports.

Chapter 9 begins with coal resources and reserves. After discussing coal prices, transportation costs and domestic demand, it examines exports, in the context of world coal markets, production and imports.

Chapter 10 draws together the sources and uses of primary energy, incorporating the projections of primary demand for domestic and export markets and of primary energy production of the preceding chapters. The chapter assesses primary energy supply/demand balances and net exports, and also provides an international perspective, showing Canada's energy use compared with that of other countries.

Chapter 11 sets out our major conclusions.

Appendix 1 provides abbreviations of names, terms and units; conversion factors; and definitions.

Appendices 2 to 10 provide supporting data for Chapters 2 to 10 respectively.

Appendix 11 provides the phone numbers of persons to whom any questions on this report should be directed.

Chapter 2

Economic Performance and World Oil Price Outlooks

In this chapter we develop two projections of world oil prices based on two scenarios of international economic performance. We then discuss the profiles of Canadian economic growth which we have developed consistently with our international growth and oil price outlooks.

Our analytical framework for making these oil price projections consists of international demand and supply outlooks, which include an assessment of OPEC supply management capability in the context of world demand and of non-OPEC oil supply conditions.

We make these projections at a time when:

- there is a considerable surplus of productive capacity on the world oil market,
- OPEC has not been able to sustain oil prices above the $US 15 to 18 range over the past several years,
- low oil prices do not appear to have stimulated a major trend of increasing oil demand, and
- there is much uncertainty about future international economic performance - a major factor influencing demand for all energy.

In these conditions, we think it reasonable to adopt the perspective that international economic growth will be the primary factor influencing demand for oil. Higher oil demand growth increases the call on world supply. As incremental supply of non-OPEC oil becomes more expensive with cumulative production, world prices increase. The price increase has mild negative impacts on oil demand and on economic growth in countries which are net oil importers, but these impacts do not outweigh the primary impact on oil demand due to world economic growth.

The main factor which distinguishes our high case from the low is that world economic growth is higher in the high case, causing higher demand for oil and a higher oil price path.

OPEC has more scope to influence prices in the high case than in the low because the cost of non-OPEC supply is increasing more quickly, and higher world demand gives OPEC a larger market share. This makes cohesion within the organization easier to achieve because there is less difference of interests between those who want higher current prices and those who want a sustained, larger world oil market, even at the cost of lower current prices.

Our price projections should be viewed as long term paths representing our assessment of the outer bounds for prices which are sustainable in the longer term. In reality, oil prices will fluctuate above and below these paths, as well as within them, but we make no attempt to project the timing and size of these fluctuations.

Given the international economic growth and oil price conditions for the two cases, we then construct consistent projections of Canadian economic performance over the study period for each case. Canada is an open economy and international economic conditions influence the extent to which Canada's growth potential can be achieved. Thus in the high case, higher export potential is conducive to higher economic growth. In the low case, poorer prospects on world markets cause Canada's economy to grow at a lower rate than it does in the high.

We also examine the industrial distribution of growth in Canada in both cases. It makes a difference to energy demand growth whether the service sector grows more or less quickly than the goods-producing sector. The sectoral distribution of growth also causes differences in economic and energy demand growth rates between the regions of Canada, because the composition of economic activity varies from one region to another. We present our projections of economic activity by sector and by region in Section 2.2 of this Chapter, and the corresponding energy demand in Chapter 4.

2.1 World Economic Performance and Oil Prices

Our two scenarios for the world economy (apart from the centrally planned economies) have growth averaging about 2 percent per year in the low case and 3 percent per year in the high over the study period. Different countries will grow at rates different from these averages, and there will be variations in the rate of growth of economic activity over time, which we do not attempt to portray.

Rather, we view our economic growth projections in much the same way as our oil price projections; as representing high and low paths which are sustainable on a long-term basis.

Much of the stimulus to growth in the years since 1982 has come from expansion of the U.S. economy, partly fueled by domestic fiscal expansion, which has raised major concerns about the size of the U.S. budget deficit. A consequence of this expansion has been the accumulation of large trade deficits, as imports increased by more than exports. European countries have generally pursued more restrictive monetary and fiscal policies; a number of them have higher unemployment rates than does the U.S. They have contributed less to international economic growth and been a less buoyant market for other countries' exports.

While many third world economies grew fairly rapidly in the 1960s and early 1970s, contributing substantially to the export growth of OECD countries, with some exceptions they have been experiencing low growth in recent years and serious problems of deteriorating terms of trade with other countries, very large external debt service obligations, inadequate capacity to import, domestic inflation and high unemployment. Many developing economies do not have the means to emerge from these difficulties solely on the basis of their own initiative.

The prospects for world economic growth depend to a large extent on whether the major industrial countries are able to coordinate their economic policies so as to resolve the major imbalances which presently characterize the world economy. These imbalances relate to the large government and trade deficits in the U.S. and the relatively restrictive macroeconomic policies in place in the Japanese and German economies which tend to sustain trade surpluses in those countries. The policies which generate these imbalances in the industrialized world have the effect of maintaining real interest rates at historically high levels and make it very difficult for the developing countries to manage their debt burden.

Our high growth scenario is based on the premises that:

- the U.S. achieves steady reductions in its federal government deficit;
- other major OECD countries, notably Germany and Japan, take steps to expand their economies to offset the effects of the restrictive fiscal policy in the U.S.;
- as a consequence faster growth in European and Japanese economies, combined with the depreciation of the U.S. dollar results in a reduction of the U.S. trade deficit;
- these policies lead to lower real interest rates and this, combined with stronger commodity prices which result from sustained growth in the industrialized world, makes the debt burdens of developing countries more manageable.

In this case, macroeconomic and structural policies enhance U.S. international competitiveness and the character of international co-operation and co-ordination is conducive to high sustained growth. Some European countries and Japan allow their economies to grow faster, attracting more exports from the U.S. and developing countries, helping to improve international trade and payments imbalances; as well there is much less incentive for deficit countries to adopt protectionist trade measures. With more growth-oriented domestic management policies and a more open international trading system, there is an improved climate of investor confidence, possibly a higher rate of technological change and better economic performance overall.

We characterize this scenario with a 3 percent long-term world economic growth rate. Growth rates sustained much above this level would tend to trigger inflationary pressures in the U.S. and some other industrial countries, absent a more dramatic acceleration of productivity growth than we have assumed.

In our low case, there is no quick or painless resolution of the major imbalances in the world economy. Japan and Europe do not agree to expand their economies enough to trigger a major increase of U.S. and developing country exports to those countries. The U.S. adopts restrictive trade, and monetary poli-

cies in order to contain inflation. This reduces economic growth in the U.S. and in other countries feeding off U.S. expansion. Higher real interest rates and constrained export markets exacerbate stagnation and debt problems in developing countries, further eroding confidence in the world trade and credit system. In this scenario, there are no sources of dynamism in the international economy; rather, there is an on-going manifestation of cautious and defensive economic behaviour.

We characterize this scenario with a 2 percent economic growth rate. In our view a growth rate much below this level would not be sustainable; it would lead to unacceptably high levels of unemployment for which alleviating measures would be taken.

Implications for World Oil Demand, Supply and Prices

The higher and lower projections of world economic performance underlie the higher and lower world oil demand projections in Tables 2-1 and 2-2. Starting with today's level of non-CPE oil demand and prices we linked world oil demand growth positively with economic growth and negatively with price, resulting in the low and high case oil demand projections respectively. Starting with 48.1 million barrels per day, low case oil demand reaches only 50.8 MMb/d by 2005, and high case demand 62.0 MMb/d.

In the low case, world oil demand grows at about 0.3 percent per year between 1986 and 2005. The composition of this growth consists of OECD growth at plus and minus 0.3 percent per year up to and beyond 1995 respectively, while non-OECD demand growth averages about 1.1 percent per year between 1986 and 2005. This growth pattern reflects low international economic growth, which in the OECD is higher in the early part of the study period and lower in the latter part. Toward the latter part of the study period, efficiency gains in OECD oil use outweigh the very modest increases in demand caused by economic growth. The oil price is low enough to compete with some alternative fuels in the switchable market, but not low enough to sustain a trend of broadly-based increased oil demand. OECD oil demand growth is much more modest than that of the non-OECD countries, whose oil demand is more sensitive to economic performance given the

Table 2-1

Low Oil Price Projection World Demand and Supply
(million barrels / day)

	1986[b]	1988	1990	1995	2000	2005
Demand Total[a]	**48.1**	**49.5**	**50.3**	**50.5**	**50.8**	**50.8**
OECD	35.4	36.3	36.7	36.3	35.8	35.1
Other	12.7	13.2	13.6	14.2	15.0	15.7
Supply						
Non-OPEC[c]	28.9	28.6	27.7	26.2	24.9	23.3
OPEC[d]	19.9	20.9	22.6	24.3	25.9	27.5
OPEC Capacity	27.5	27.5	30.0	31.0	33.0	35.0

Notes: The numbers on this table have been rounded.
[a] Excludes CPE Demand.
[b] Provisional actual; source: Petroleum Economics Ltd., London, England.
[c] Includes CPE net exports of about 2.3 MMb/d, trending down to 1.6 by 2005, and processing gain from all sources of 1.5 MMb/d.
[d] Includes condensates and natural gas liquids.

Table 2-2

High Oil Price Projection World Demand and Supply
(million barrels / day)

	1986[b]	1988	1990	1995	2000	2005
Demand Total[a]	**48.1**	**49.3**	**50.8**	**54.3**	**58.0**	**62.0**
OECD	35.4	36.2	36.9	38.7	40.0	41.0
Other	12.7	13.3	13.9	15.6	18.0	21.0
Supply						
Non-OPEC[c]	28.9	29.1	28.9	28.2	27.6	27.0
OPEC[d]	19.9	20.2	21.9	26.1	30.4	35.0
OPEC Capacity	27.5	27.5	30.0	31.0	33.0	36.0

See footnotes for Table 2-1

lower penetration of oil-using equipment in their economies. Thus in the low case non-OECD, non-CPE oil demand grows from 12.7 MMb/d in 1987 to 15.7 MMb/d in 2005.

In the high case, world oil demand grows at 1.3 percent per year between 1986 and 2005, being a composite of 0.8 percent and 2.7 percent growth per year in the OECD and other non-CPE countries respectively.

OECD oil demand growth is low but positive, rather than negative, reflecting the high average economic growth rate of 3 percent per year, the absence of oil price shocks (hence absence of major off-oil initiatives), and the fact that there remains some oil conservation and substitution achievable in current uses at these prices. Hence oil demand grows with growth in oil-specific end uses, but there are on-going gains in the efficiency of future oil use, and technological change favours the use of electricity rather than oil; therefore, growth in OECD oil demand continues at a rate well below that of economic growth.

Non-OECD oil use grows at 2.7 percent per year, reflecting high average economic growth in these countries, and relative to the OECD, robust oil demand growth. Economic development spurs increased penetration of oil; commercial energy displaces rural sources of energy, transportation use grows rapidly and so does use in industrial processes.

Demand projections alone, of course do not determine future oil prices. Demand itself partly depends upon price, and it is necessary to estimate from where the additional oil will come and under what supply conditions.

OPEC's share of the world oil market has declined substantially between 1975 and now, from satisfying about 60 percent, to less than 40 percent of non-CPE demand. OPEC's ability to constrain world oil supply has been limited. Therefore, we believe that OPEC's ability to influence supply and price will depend mainly upon international demand and non-OPEC supply. In a world of bouyant oil demand and scarce or costly non-OPEC oil supply, OPEC has more scope to manage supply and influence price than it would under conditions of low demand growth, and more plentiful, less costly non-OPEC oil supply.

Table 2-3 shows selected oil prices between 1973 and 1987. The "official price" reflects prices set by OPEC, while the spot price reflects prices which buyers and sellers negotiate on the open market. Between 1973 and 1979, the official price of light Middle East crude and the spot price moved quite closely with each other. In 1979, the spot price led the official price, triggered by an international reaction to the revolution in Iran. From that time onward, the spot market led the official market upward to 1981 and downward thereafter.

It is reasonable to infer that the international spot market served as a price barometer against which OPEC could, and eventually had no choice but to adjust its supply and pricing behaviour. In 1979 and 1980 the spot market indicated the nervous reaction of major oil customers to the events in Iran - a country which enjoys a strategic location and at that time produced about 3 million barrels per day of oil.

The escalation of oil prices up to 1981 induced major increases of non-OPEC supply (Table 2-4).

Table 2-3

Official and Spot Oil Prices

Year		Official	Spot
1973		2.64	2.81
1975		10.46	10.43
1979	Q1	13.48	18.35
	Q2	16.15	27.35
	Q3	18.89	32.90
	Q4	22.84	38.17
1980		29.38	36.00
1981		33.20	34.17
1985		28.00	27.50
1986	Q1	28.00	16.59
	Q2	28.00	11.01
	Q3	28.00	11.20
	Q4	28.00	14.10
1987	Q1/Q2	17.67	17.40

Note: Middle East light crude, denominated in nominal U.S. dollars.

Source: "World Oil Trends: a Statistical Profile" 1987 - 88 Edition, Section 19, Arthur Andersen and Co., Cambridge Energy Research Associates.

With 1986 demand barely above the 1975 level, the North American share of supply was fairly constant, while the OPEC share fell dramatically in face of very large supply development from the North Sea and the non-OECD/non-OPEC countries. (In 1985, the OPEC share was below 37 percent; Saudi production was especially affected, having decreased from 9.6 MMb/d in 1980 to 3.3 MMb/d in 1985.) Notwithstanding the relatively low prices experienced since 1986, there has been sustained and even increasing non-OPEC oil supply from many countries. Perhaps this reflects the fact that once major supply developments are initiated, accumulated expenditures are a sunk cost; there is every reason to complete and

Table 2-4

Distribution of World Oil Production

	1975	1980	1986
Demand (million barrels /day)	44.5	49.1	45.8
Supplied by		**Market Share (Percent)**	
U.S.	22.5	20.8	22.5
Canada	3.8	3.7	3.9
North Sea	0.4	4.3	7.9
Other Europe	0.9	1.0	1.3
Australia / New Zealand	0.9	0.8	1.3
Non - OECD / Non - OPEC	7.9	11.4	18.1
OPEC	61.1	55.0	40.0
CPE Net Exports	2.5	3.0	5.0

Note: Excludes internal CPE production and consumption, natural gas liquids, condensate, processing gain and stock change.

Source: "World Energy Outlook to 2000", Petroleum Economics Ltd., London, 1987.

operate these projects as long as the world oil price is sufficient to recover incremental completion and operating costs.

Now that there is a geographically diverse range of oil supplies outside of the OPEC orbit, with the ever present possibility that high oil prices would encourage more non-OPEC supply, it is much more difficult for OPEC to control the world oil market now than appeared to be the case in the late 1970s.

The post-1980 experience must have been a very sobering one from an OPEC perspective. Table 2-5 shows what happened to the real international purchasing power of OPEC oil revenue from 1975 to 1986. To derive real international purchasing power of nominal revenues, it is necessary to adjust them for both price inflation of the goods and services they buy, and fluctuations in the value of the U.S. dollar; (revenues are earned in dollars, but spent on imports from many other countries, the values of whose currencies change vis-à-vis the dollar.)

The real purchasing power of OPEC revenue shown in the last column is an approximation, because the conversion from nominal U.S. dollars to real SDR does not exactly reflect each foreign currency share of OPEC imports. Nonetheless, it is clear that, since 1982, OPEC's real income was less than in 1975; in 1986 its real income plummeted to less than its 1973 real value, before the major oil price increases of the 1970s occurred. Even at $US 28 per barrel (in nominal dollars) in 1985, OPEC's real revenues were only slightly more than one half their 1975 value, reflecting the combined impact of falling market share and international inflation. Clearly, the OPEC revenue position of 1980 and 1981 was an exceptional and unsustainable experience.

Apart from international supply and demand factors beyond OPEC's direct control, OPEC countries have divergent interests which make it difficult for the group to agree upon output levels and quotas, and hence to control the price.

At least three categories of countries are members of OPEC:

(i) Iran/Iraq,

(ii) the "high reserve-low absorber" countries and

(iii) the "low reserve-high absorber" countries.

It was difficult for Iran and Iraq to abide by quota allocations when the two countries were at war with each other and needed revenue to sustain that war. The major uncertainties about Iran/Iraq oil supply are whether hostilities will be ended indefinitely, and whether those countries will sharply increase oil output to earn revenues needed for reconstruction, or

Table 2-5

OPEC Revenues

Year	$US (Billion Nominal)	Real SDR[a] (Billion)
1973	37	38
1975	107	92
1976	129	102
1977	140	97
1978	135	81
1979	201	109
1980	287	142
1981	266	131
1982	208	100
1983	163	79
1984	149	73
1985	132	55
1986	77	28

Notes: The numbers on this table have been rounded.

[a] Nominal dollars are converted to SDR at the average exchange rate for the year, and deflated using a total OECD CPI deflator.(The SDR is International Monetary Fund Special Drawing Rights; the SDR is valued on the basis of a basket of several major currencies).

Souce: "World Oil Trends, 1987-88 edition", op.cit,

cooperate closely with other OPEC countries in trying to manage the supply of OPEC oil on the world market. In our projections, the Iran/Iraq share of OPEC supply increases moderately in the high case, but is stagnant in the low case.

The "high reserve-low absorber" countries (Saudi Arabia, Kuwait, Abu Dhabi and the United Arab Emirates) have very large oil reserves and potentially large undiscovered resources, but relatively low current revenue needs given their small populations. They can increase their revenue by increasing their output, provided that in so doing they do not depress the world oil price by proportionately more than they increase their output. These countries have an interest in preserving the long-term market for oil, because they have the world's largest reserves and little interest in pricing it out of the world's energy future now.

The "low reserve-high absorber" countries (such as Algeria, Nigeria and Indonesia) have relatively large and urgent revenue needs, but little surplus productive capacity and, compared with the other groups, relatively limited oil reserves; hence it is very difficult for them to increase revenue by increasing output - they must rely on increasing the price.

If there were an expanding world oil market, with demand increasing by more than non-OPEC supply, the needs of these groups would be more easily satisfied with increasing OPEC market share, output and prices. However, with weak demand and little scope to increase price unless total oil output falls, there is a conflict between those who prefer more output at lower prices and others who prefer less output at higher prices.

This conflict is exacerbated when it falls to the larger producers - especially Saudi Arabia - to curtail *their* output, in order to defend higher world prices than they think desirable relative to either their revenue requirements or to their long term interests in serving a large world market for oil. It was Saudi Arabia's refusal to play this "swing producer" role in face of an "oversupplied" market which triggered the price collapse of 1986. Saudi Arabia has since re-iterated its intention not to be a swing producer.

Since 1986 the prices of Middle East light crude have fluctuated in the $US 15 to 20 range, more often in the $US 16 to 18 range. There have been a number of difficult meetings between OPEC members designed to prevent a re-occurrence of the 1986 experience. Initiatives to secure agreement on output restraint between OPEC and non-OPEC producers have been unsuccessful. Recent experience suggests that low oil prices have not triggered substantially higher growth in oil demand, non-OPEC oil supply continues to increase and, for the time being, OPEC has managed to avoid another price collapse akin to that of 1986, but has been insufficiently cohesive or influential to sustain a price above the $US 15 to 18 range.

For our supply projections, we estimated potential non-OPEC supply at different prices in the range of $US 15 to 30 per barrel, starting with today's level of non-OPEC supply. The quality of information available for making this projection is less than desirable, hence there is more than usual uncertainty about projections of non-OPEC volume:cost relationships. OPEC supply is the difference between demand and non-OPEC supply in Tables 2-1 and 2-2 for the low and high cases respectively.

Our price projections (Table 2-6) are shaped on the basis of the estimated incremental supply costs of non-OPEC oil over time, which increase more rapidly in the high case than in the low, given relatively higher demand and resource exploitation in the high case.

The price projections are intended to be sustainable paths, reflecting the combined impacts of world economic growth on the demand for oil, and of international resource development activity on the supply of oil.

Comparing the high scenario with the low one, in the high case, stronger economic growth causes stronger oil demand, more rapid movement into higher cost non-OPEC oil supply and a more rapid increase in OPEC's share of the oil market. The high scenario price is limited to $US 30 (in 1987 dollars) per barrel because we do not believe that a price above $US 30 would likely be sustainable –

Table 2-6

World Oil Price Projections

Year	Low Case	High Case
1986 [a]	16.00	16.00
1988	15.00	20.00
1990	15.00	22.00
1995	16.00	27.00
2000	18.00	30.00
2005	20.00	30.00

Notes: $US (1987) for West Texas Intermediate at Chicago.
[a] Actual.

Source: Appendix Table A2-1.

alternative oil and other energy supplies would emerge and demand would react to prevent prices from being sustained much above $US 30 per barrel.

The low scenario does not reach $US 30 per barrel because over our study period cumulative demand and non-OPEC supply conditions do not indicate a sustainable price much above $US 20 per barrel. The low case has a minimum price of $US 15 per barrel, based on three considerations:

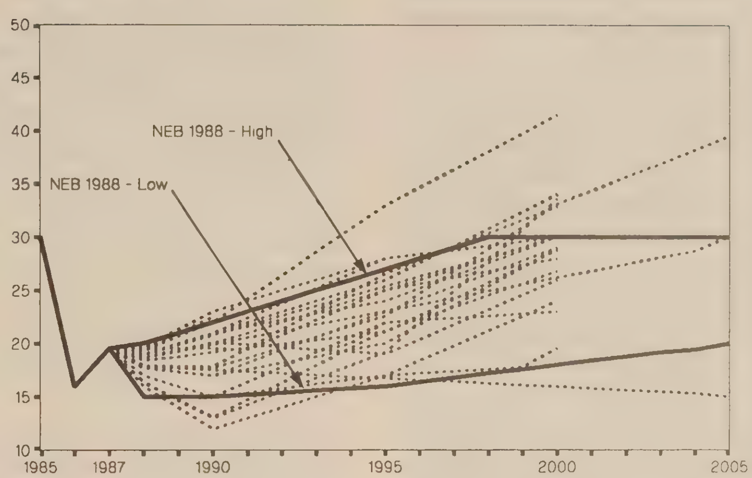
- at the outset of the projection it reflects an approximate "floor" of oil price behaviour since the post-1986 price recovery;
- prices below $US 15 per barrel may not be sustainable because of the negative impact such prices would eventually have on non-OPEC supply and the mild stimulus they would give to demand;
- once the oil price falls to $US 15 per barrel, heavy fuel oil would be generally competitive with its major competing fuels, such as coal, meaning that it would not pay producers to put more oil on the market and let the price fall further: the increase in demand would not be commensurate with the fall in price, hence total oil revenues would decrease.

Figure 2-1 shows our oil price projections along with the range of other projections (dotted lines) which we have examined. Figure 2-2 shows our projections in this report, compared with those of the October 1986 Report, adjusted to 1987 dollars.

The main features of the low price projection are:

Figure 2-1
Comparison of World Oil Price Outlooks

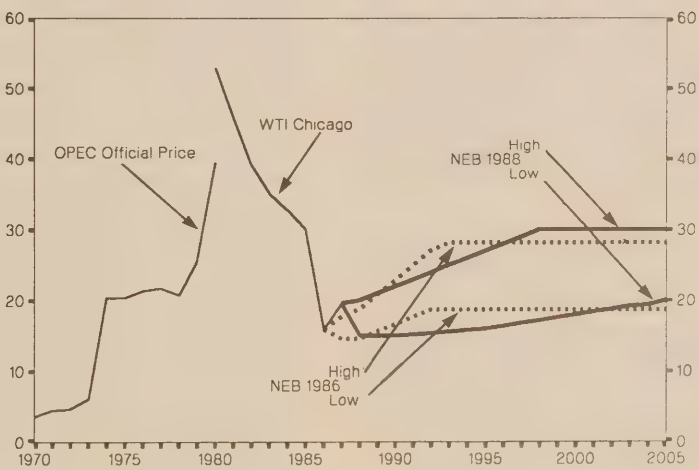
($US 1987/BBL)



Source: Appendix Table A2-1.

Figure 2-2
World Oil Prices

($US 1987/BBL)



Source: Appendix Table A2-1.

- World oil demand grows at 0.3 percent per year. OECD demand growth is at first positive then negative, while non-OECD demand growth averages about 1.1 percent per year between 1986 and 2005.
- Non-OPEC supply falls considerably more in this case than in the high scenario, because the demand and price conditions are less conducive to supply developments in these countries. However, because demand is relatively constrained, OPEC production is also well below high scenario levels.
- OPEC's share of the world market reaches about 50 percent by 2000 and 54 percent by 2005. The OPEC capacity profile is similar to that of the high case, because prices are not low enough to completely discourage expectations and nullify the viability of capacity expansion. Countries expand capacity based on individual considerations and they do not have perfect foresight over international supply and demand conditions or prices in the long term.
- In this scenario, there is little scope for OPEC management of the international oil market, as the potential for more non-OPEC supply is high were prices to increase.

The main risks to this projection are:

- OECD demand growth may be stronger than indicated, putting upward pressure on price later in the study period.
- Because oil prices are low, non-OPEC supply may be less than anticipated in the early part of the study period, giving OPEC a higher market share and more room to influence price until non-OPEC oil production eventually resumes.
- On the other hand, with technological change and other industry adjustments to a low price world, non-OPEC supply may be greater than shown throughout the study period, sustaining a flatter price path, which fails to reach $US 20 per barrel by 2005.

The major features of the high price projection are:

- World oil demand grows at 1.3 percent per year between 1986 and 2005, consisting of 0.8 percent and 2.7 percent growth per year in the OECD and other non-CPE countries respectively.
- Non-OPEC supply declines only very gradually, because there is sufficient demand and price incentive to maintain supply at near current levels.
- OPEC's market share increases from about 41 percent in 1986 to about 56 percent by 2005. Thus it does not reach its level of the early 1970s by the end of our study period.
- OPEC capacity gradually increases, reflecting an expectation that Iran and Iraq will re-build productive capacity; in all countries, exploration and development activity continues and yields some incremental productive capacity; by the late 1990s, OPEC achieves satisfactory rates of capacity utilization, relative to those prevailing now.

The main risks to this price path are:

- World oil demand may grow more than portrayed, most probably reflecting higher non-OECD demand growth.
- Oil prices may not reach the $US 20 to 22 range between now and 1990; this would dampen non-OPEC supply development, eventually increasing OPEC's market share and providing more potential for OPEC price management. This sequence of events could then accelerate non-OPEC supply development, but with a lag.
- Non-OPEC oil may be less abundant, less timely and more costly to develop than this projection assumes. Between 1987 and 2005, the sustainability of this projection requires a cumulative total non-OPEC output of about 166 billion barrels, relative to estimated recoverable reserves of about 203 billion barrels.

All of these factors singly or in combination would generate a higher sustainable oil price path in the 1990s, relative to that in our projection.

In neither case do our projections include price shocks; oil prices change gradually and do not in themselves trigger declines in economic activity. In reality, it is reasonable to expect that oil prices will fluctuate from time to time above and below the high and the low paths we project.

Smooth price projections tend to mask a difficult issue: price volatility adds to uncertainty and uncertainty discourages investment - particularly if it implies a range of conceivable project results which imply more risk than investors believe worthwhile undertaking, given the range of rates of return they wish to earn. It would not be surprising to see highly volatile oil

prices accompanied by less non-OPEC oil supply, fewer energy mega-projects and higher sustainable oil prices than those projected in this report.

We have not attempted to portray price volatility, as this is very difficult to do in a credible way over the study period. Furthermore, our primary objective is to analyze what difference it would make to Canadian supply and demand for energy if the international economic and oil price environment generally resembled that of either the high or the low scenario, on the assumption that some price volatility is expected and would not generate economic behaviour much different from that in our scenarios. We acknowledge, however, that recent historical experience suggests it may well be sensible to characterize future oil markets in terms of considerable price volatility.

2.2 Canadian Macroeconomic Performance

Our projections for Canada's macroeconomic performance are based on the two international outlooks described in Section 2.1.

The rate and character of Canadian economic growth are important determinants of the amounts and types of energy which Canada will require over our study period. Since energy is used in the production of goods and services, it follows that the higher the rate of economic growth the higher will be the demand for energy in Canada. Energy demand is also powerfully influenced by the composition of Canadian growth. Some industries use energy in their production processes much more intensively than others; for example, production of pulp and paper requires thirty times as much energy per dollar of output as does the production of services. Energy is also an input in the production of goods such as plastics and synthetics, industrial and agricultural chemicals. Thus an assessment of energy demand in Canada depends not only on the rate, but also on the composition of Canadian economic growth.

In the long run Canadian economic performance will be determined by the rates of labour force and productivity growth. These factors determine the rate of potential growth in the economy.[1]

The rate of labour force growth is known with reasonable certainty. The participation rate times the working-age population determines the size of the labour force. It is generally accepted that Canadian population growth will slow as fertility rates decline. For the next twenty years, the population which will form the basis of the labour force is already largely determined, although net immigration assumptions may have a modest impact on the aggregate. The increase in female participation rates has slowed in recent years. While we expect some continued gains in the future, we do not anticipate growth rates as high as those of the 1970s. We expect the aggregate participation rate to stabilize at about 68 percent - taking account of trends of the different age-sex categories. In both the high and low cases we anticipate labour force growth to average about one percent annually over 1986 to 2005.

Productivity is more difficult to project. During the 1960s, Canada's output per person grew at almost three percent per year, but this performance eroded gradually during the early 1970s and then fell to only a 0.1 percent annual increase over 1973 to 1981. More recently, with the economic recovery from the 1982 recession, growth in output per worker has averaged just over 1.5 percent annually.

There have been many studies attempting to identify the causes of the productivity slowdown of the 1970s, to determine whether these might have an impact on future long-term productivity prospects. All studies have identified cyclical causes (such as unexpectedly low sales, changes in the relative price of energy, low profitability of industry, and substitution of labour for energy and capital), but there has been no conclusive evidence which would argue against a long-term recovery of productivity growth.

While we project productivity growth above that of the 1970s - averaging 1.4 percent annually over 1986 to 2005 in the high case and 1.1 percent in the low - these rates are well below those experienced in the 1950s and 1960s. A more favourable international environment in the high case, coupled with stronger investment are the main causes of the higher productivity growth in that case.

In the high scenario we assume that the U.S. and the industrial world generally follow policies

---

1. Potential growth is approximately equal to the sum of labour force and productivity growth. It represents the upper bound to growth for a given unemployment rate. However, under favourable international conditions, Canadian growth could exceed potential for a period of time, if there are underutilized resources in the economy. In a similar vein, if international conditions are not favourable, Canadian growth could fall short of potential, and the country could experience a rising unemployment rate.

which promote an open and dynamic world economy and which permit those economies to operate close to their potential without a renewed outbreak of inflation. This economic environment is conducive to relatively high productivity growth. The low scenario on the other hand contemplates a world in which the major industrial economies retreat to more protectionist and restrictive policies and in which rates of unemployment are at relatively high levels. There is less investment, lower turnover of capital stock and productivity growth remains relatively low.

These alternative views of the evolution of the world economy powerfully influence Canadian performance because we are an open economy. (We present a brief overview of recent economic performance in the inset.) Within this world framework Canadian economic growth will also be determined by internal factors including domestic policies (monetary, fiscal and structural) and regulatory and institutional structures which can affect productivity and labour force utilization.

Turning to our projections, in the high case, Canada's real gross domestic product averages 2.9 percent annual growth from 1986 to 2005. Labour force growth of one percent per year and annual productivity gains of 1.4 percent combine with a slow though steady decrease in the unemployment rate (from its current eight percent range to about five percent towards the end of the projection) in this case. Real short-term interest rates average four percent in the near term, but decline to about 2.5 percent by the mid-1990s. Inflation averages close to five percent per year through most of the projection period. Real personal disposable income growth aver-

Recent Economic Performance

During the 1960s Canada's real output grew at just under six percent annually, close to potential, as the unemployment rate varied between three and five percent. During the 1970s real output growth averaged four percent, somewhat below potential, and the unemployment rate rose to 7.5 percent by 1980. The recession of 1982 was the most severe since the 1930s, and affected all industrialized countries, though Canada's decline was among the most pronounced. Real output declined by four percent in 1982,[1] concentrated in the industrial sector (forestry, mining, manufacturing and construction) which experienced an eleven percent decline. The recovery from the recession has been uneven. Some sectors of the economy and some categories of expenditure (most notably nonresidential investment) have only recently recovered to pre-recession levels, despite five years of strong aggregate performance, averaging four percent annually since 1982. The timing and severity of the recession varied as well by province. Energy price declines since 1982, poor crop yields and weak commodity prices have left the three western provinces lagging the recovery of central Canada.

Just as reduced demand for Canadian exports was an important factor in the 1982 recession, the recovery of the United States economy since then, and the recovery of Canada's exports have been a critical element in growth since that date. Canada's ability to compete in international markets over the last decade may be attributed largely to the devaluation of the Canadian dollar, from parity with the United States dollar in the mid-1970s, to a low of $US 0.719 in 1986. It subsequently recovered to almost $US 0.77 by the end of 1987. This devaluation offset increases in manufacturing unit labour costs which exceeded those of the U.S., Germany and Japan over that period, allowing Canadian exports to remain competitive in foreign currency terms.

1. All analysis is based on 1971 dollar (GNP) data, as the disaggregated economic data required by the NEB's energy demand models was not available on a 1981 basis when the analysis was undertaken. For all economic and energy demand data 1987 is an estimate, 1986 is the last year of actual data. Work on the scenarios began in March 1988 and the energy demand projections were completed in July 1988. Thus it was not possible to incorporate actual values for 1987 in the analysis.

ages 2.3 percent annually, 1986 to 2005, or one percent per household.

This economic growth is sustained by the strong external environment, which increases Canada's export growth.[1] The major contributors to growth are exports (with annual growth in the 3 to 3.5 percent range) and nonresidential investment (at about four percent per year). Personal consumption growth slows over the period from 2.5 to three percent during the first half of the projection period, to about two percent during the last half.

In the low case policies are less conducive to high economic growth. A more protectionist world economy results in Canadian economic growth of only two percent on average, between 1986 and 2005. Productivity improves less rapidly than in the high case, growing at just over one percent per year. The labour force grows at one percent per year as well. In this case, the unemployment rate rises gradually to 9.5 percent, where it remains for most of the outlook period. Monetary policy is more restrictive internationally. This case assumes that, in the absence of policies to deal with government and trade deficits, the United States uses restrictive monetary policy to contain inflationary pressures. Canada's short-term real interest rates average five percent in the near term, declining to 4.5 percent thereafter, and inflation averages close to four percent, over the projection period as a whole. Real personal disposable income increases by 1.7 percent annually, on average, or 0.4 percent per household. All expenditure categories - consumption, investment, government and net trade grow less rapidly in this case than in the high case.

An important aspect of our macroeconomic projections - particularly in determining energy demand - is the relative growth of "goods" and "services" industries. Goods producing industries (the industrial sector) include forestry, mining, manufacturing and construction. Within the industrial sector the most energy intensive industries are mining, pulp and paper, iron and steel, smelting and refining, chemicals, cement and petroleum refining.

Service producing industries (the commercial sector) combine four distinct categories: wholesale and retail trade; finance, insurance and real estate; public and private services and public administration. For purposes of energy demand projections agriculture, utilities and transportation, storage and communications are treated separately.[2]

For the past fifteen years the share of services in real gross domestic product has been rising; correspondingly the share of goods producing industries has been declining. This is an important matter for our projections, because energy use per dollar of real output in the industrial sector is four to five times greater than that for the commercial sector. Within the industrial sector, however, a subset of energy intensive industries use about ten times as much energy per dollar of real output as other industries. Hence the projected evolution of energy intensive industries is also important to our demand projections.

The composition of Canadian economic activity evolves differently in the two cases. In the high case world demand for our exports is relatively strong; as a consequence, growth is strongest for durables manufacturing where Canada has comparative advantage in international trade. In the low case economic activity is governed to a greater extent by domestic demand.

Our projections of industrial output reflect projections of expenditures by commodity, including export demands. The share of industrial output in total real gross domestic product increases from 29 percent in 1986 to about 33 percent in 2005 in the high case and to 31 percent in the low case (Table 2-7). Energy intensive industries, which contributed 7.4 percent of total output in 1986 account for 7.1 percent and 6.8 percent in 2005 in the low and high cases, respectively.

Within the industrial sector, manufacturing shows the strongest growth in both cases, 2.6 percent

---

1. In this context, we have assumed that in both cases the exchange rate maintains a level of $US 0.78 per Canadian dollar. Many factors influence exchange rate movements, from tangible indicators such as real output growth, current account and government balances and interest rate spreads, to less tangible perceptions on the part of traders and investors of the outlook for the country, of the management by government of the economy and of Canada's prospects relative to other countries. While we recognize that some would argue for a stronger currency under a higher growth scenario, and that the exchange rate has a very important impact on Canadian oil prices, we have not attempted to assess the varied and often conflicting determinants of the exchange rate.
2. Energy demand for agriculture is included in the residential sector; energy demand for transportation is analysed separately; energy use by storage and communications is included in the commercial sector (though RDP is not) and utilities energy consumption appears as utilities' own use. The classification of goods and services is based on the NEB's energy demand data classifications. Our discussion of historical performance of these two sectors is also based on this categorization.

Table 2-7

Distribution of Real Gross Domestic Product (1971 dollars)

(Percent)

	1973	1986[a]	2005 Low	2005 High
Industrial Sector	35.1	29.1	30.7	32.7
Forestry	0.8	0.6	0.6	0.6
Mining	3.9	2.6	2.2	2.4
Manufacturing	23.9	20.9	22.6	24.6
Construction	6.5	5.0	5.3	5.1
Commercial Sector	49.5	54.0	52.2	50.2
Other[b]	15.4	16.9	17.1	17.1

Notes: [a] Estimate.
[b] Other includes agriculture, utilities, transportation, storage and communications.

Table 2-8

Output by Sector (1971 dollars)

Average Annual Growth Rates (Percent)

	1986-1990 Low	1986-1990 High	1990-2005 Low	1990-2005 High	1986-2005 Low	1986-2005 High
Industrial	1.9	3.5	2.6	3.5	2.5	3.5
Forestry	1.8	2.1	2.1	2.5	2.0	2.4
Mining	0.6	2.8	1.5	2.4	1.3	2.5
Manufacturing	2.1	3.7	2.7	3.8	2.6	3.8
Construction	1.5	3.0	2.8	3.0	2.5	3.0
Energy - intensive[a]	1.8	3.6	2.1	3.2	2.1	3.3
Commercial	2.5	2.8	1.8	2.4	2.0	2.5
Total Gross Domestic Product	**2.3**	**3.1**	**2.0**	**2.9**	**2.2**	**2.9**

Note: [a] Mining, smelting and refining, iron and steel, pulp and paper, chemicals, cement and petroleum refining.

annually over 1986 to 2005 in the low, and 3.8 percent in the high, while in both cases growth of the energy intensive industries is slightly below the manufacturing aggregate and that of the sector as a whole (Table 2-8). The composition of export demand favours durable and, to a lesser extent, non-durable manufacturing. Among the energy intensive industries, pulp and paper is expected to face resource constraints in the future, which will restrain output growth. Canada's other major resource industries face competition from developing countries who are building their resource sectors and penetrating world markets.

Commercial sector output accounts for 50 percent of total output in 2005 in the high case and 52 percent in the low case as compared to 54 percent in 1986. It grows less rapidly than the industrial sector in both cases.

The difference between industrial and commercial sector growth is less pronounced in the low case. This reflects the fact that lower economic growth in the low case results largely from lower growth in exports and investment. Since these components of real gross domestic product consist largely of goods, growth in goods producing industries is most affected by the different economic environment assumed in the low case. The underlying demographic foundation of much of the service sector (health, education) is common to both cases.

Growth of individual industries within the commercial sector is generally below that of the aggregate economy for the period 1986 to 2005. This is because low population growth is expected over the period. However, for those ser-

vices which are directly related to demographic trends, our projections allow for growth in the per capita production of those services in excess of one percent annually in both cases.

The trends in goods and service production in our projections differ from those of the past fifteen years. Over that period services output increased more rapidly than that of goods; as a result the service sector's share of total output increased (Table 2-7). A discussion of some reasons for this past trend and factors affecting growth in our projections appears in the inset.

The regional distribution of economic growth is heavily dependent on the distribution of national growth between goods and services. The western and eastern provincial economies are relatively more dependent on resource-based industries than are the central provinces in which services and secondary manufacturing are more prevalent.

Manufacturing accounts for just over ten percent of the Atlantic region's output; in Manitoba the share is just over eleven percent, five percent in Saskatchewan, nine percent in Alberta and about 14 percent in British Columbia. However, in Quebec and Ontario manufacturing represents over 23 and 28 percent of those provinces' output, respectively.

The high case contains a large number of specific energy projects and higher activity in the oil and gas sector generally relative to the low case. The impact of major energy projects on the region in which they are located depends on a number of important factors: the sourcing of construction material and equipment (from within the region, outside the region or out-

Trends in Goods and Services Production

From the mid-1960s to 1973 the shares of goods and services production were relatively stable, but there has been a steady decline in the industrial sector's share of total real output since 1973 (Table 2-7). In Canada, it fell by about six percentage points between 1973 and 1986, while the service sector share increased by about 5.5 percentage points.

On the services, or commercial sector, side, it is useful to separate the component industries into two groups. Wholesale and retail trade and finance, insurance and real estate provide services which are related to the production and consumption of goods and services in the economy as a whole. Wholesale and retail trade, and finance, insurance and real estate have grown faster than the economy as a whole over the past fifteen years and have correspondingly increased their share of output. During this period there have been significant social and lifestyle changes, the introduction of new services and increased reliance on services over private consumption - for example, meals consumed outside the home. Studies of the reasons for this trend have been unable to identify specific causes and it is difficult to determine whether this trend will continue.

The remaining components of the sector are: health and education, private business services, which include such activities as business consulting services, and public administration. Health, education and public administration account for about one-third of the commercial sector's output.

Requirements for health and education services depend on the growth and composition of the population. Over the past twenty years the health sector's output has grown less rapidly than that of the overall economy, although there have been strong increases in real expenditure per capita. Real output growth in education far exceeded that of the total economy between 1961 and 1970, as this was a period of rapid increases in enrolment at all levels. During the 1970s and 1980s growth in education output has been sharply curtailed as enrolments continue to decline at the elementary and secondary levels. Both of these sectors - health and education - are now facing budget restrictions as provincial governments attempt to balance their budgets.

Continued on next page

Continued from previous page

Thus with slower population growth relative to the 1960s and 1970s and medium term budget constraints, growth of output in these two sectors may be expected to slow relative to the past, even though it continues to increase in real terms per capita.

Growth of public administration output was below that of the total economy from 1961 to 1981, exceeded it during the recession, but is now constrained by concerns over government fiscal balances. We do not anticipate any change in this position.

While we can examine trends within the industrial and commercial sectors and identify factors which have contributed to the shift in shares over the last fifteen years, it is not possible to determine conclusively whether this trend of increasing commercial sector share will continue or not, and if so, to what degree. In developing our macroeconomic projections we have examined specific requirements for outputs of public services such as health and education, and we have considered the role of private services - such as wholesale and retail trade and finance, insurance and real estate in meeting the needs of a growing economy.

In our projections we have allowed for real per capita increases in expenditure for public services such as health and education of approximately one percent annually. This reflects continued demands by the public for improved services in these areas, but also a recognition of funding constraints on the part of governments. Private service growth is in line with overall economic activity on the premise that ultimately these industries provide services which are related to the production and consumption of goods, and we have no compelling evidence upon which to project that they will grow faster than the other sectors which use their output. The aggregate service sector growth rate turns out to be less than that of the industrial sector because health, education and public administration grow by less than do private services and the latter grow by slightly less than the rate of the industrial sector.

side of Canada); the sourcing of labour for the construction project which in turn depends on the size of the labour force and the skills required to operate the project.

Some energy developments may contribute to a substantial increase in a province's growth during the construction phase - particularly if the materials can be produced within the province. However, once construction is completed, the province may actually witness a decline in its output as investment activity falls off. During the operations phase, as energy is produced, the impact will depend on the size of the operations labour force and the size and distribution of revenue flows and their expenditure (or saving). In the context of oil and gas production, it is also important to consider whether other, conventional, sources of production are declining, and what the resulting profile is for total energy output.

Our projections for the industrial sector, and in particular the demand for manufactured goods relative to other industrial production, result in relatively stronger growth of Ontario and Quebec in both cases, though high case growth of the Prairies and British Columbia is very close to that of Quebec (Table 2-9).

In the Atlantic region growth lags the national average in both cases, although the area benefits from the development of Hibernia in the high case. The region's manufacturing activities are concentrated in the food and beverage and pulp and paper sectors, the performance of which is not anticipated to lead activity. The region's construction and mining sectors benefit from the Hibernia project in the high case, although with completion of the construction, that

sector's output declines to more normal levels.

Quebec's economy performs close to the national average in both cases. Continued hydroelectric development in the high and low cases is a major source of investment in the province, as in the past. Quebec's manufacturing output is concentrated in nondurables production, which in our scenarios does not experience the same degree of demand growth as do durable goods. The mining sector in the province performs well in both cases - averaging between two and 3.5 percent growth annually over the projection period. Resource constraints in the forestry sector, however, are assumed to restrict prospects for forestry and pulp and paper, and output grows at or below two percent per year.

Ontario is the major beneficiary of demand for durable goods. The motor vehicles and parts industry continues to post steady gains as foreign manufacturers move production to Canada. Primary metals - including iron and steel production - and metal fabrication also contribute to Ontario's performance in both cases, as they supply Ontario's manufacturing sector with required inputs. We expect investment growth to slow down in both cases in the medium term, following recent very high rates of growth resulting from the implementation of major projects in a number of sectors. The slowdown is more pronounced in the low case. Although residential construction growth has been at record levels recently and is expected to slow, we project that it will keep pace with Ontario's overall activity.

Economic activity in the Prairie region varies by province, reflecting the different sources of growth across the region. In Manitoba, the service sector accounts for approximately 55 percent of the province's activity, followed by manufacturing at 11.5 percent and transportation at 9 percent. In Saskatchewan, services account for 44 percent of output followed by agriculture (14 percent), resource extraction and transportation (8 percent each). In Alberta services account for 47 percent, resource extraction 10 percent, transportation 10 percent and manufacturing 8 percent.

In the low case poor crop yields at the beginning of the projection period and low energy prices combine to yield growth averaging less than one percent per year for the Prairie region to 1990. In the high case the prospects are brighter as energy prices are higher and mining and manufacturing activity stronger. During the 1990 to 2005 period, economic growth occurs at close to the national average in both cases, at 2 and 2.7 percent annually in the low and high cases respectively.

Although we have included in the high case several specific energy projects (see Chapters 6 and 7) which are located in the Prairie region and are assumed to be built in the 1990s, the region's economy does not show evidence of a prolonged period of extraordinary growth. Construction and mining activity - particularly in Alberta - picks up for several years, but during this period the production of conventional crude oil is declining and the output of these new projects is not enough over the long run to offset this trend.

In British Columbia services account for just under 50 percent of output, manufacturing 14 percent, transportation 10 percent, construction 5 percent, resource extraction 4 percent and forestry 3 percent. In both cases we expect that resource constraints will limit growth in the forestry and pulp and paper sector. Growth of the other resource sectors and British Columbia's relatively small share of

Table 2-9

Output by Region (1971 dollars)

Average Annual Growth Rates (Percent)

	1986-1990		1990-2005		1986-2005	
	Low	High	Low	High	Low	High
Atlantic	2.1	2.7	1.7	2.6	1.8	2.6
Quebec	3.2	3.5	1.9	2.6	2.2	2.8
Ontario	2.6	3.3	2.4	3.2	2.4	3.2
Manitoba	2.1	2.4	2.0	2.5	2.0	2.5
Saskatchewan	1.4	2.4	2.2	2.9	2.1	2.8
Alberta	-0.3	2.5	2.0	2.7	1.5	2.7
Prairies	0.6	2.5	2.0	2.7	1.7	2.7
British Columbia and Territories	2.0	2.2	2.1	2.6	2.1	2.5
Canada	**2.3**	**3.1**	**2.0**	**2.9**	**2.2**	**2.9**

manufacturing (as compared to that of Ontario or Quebec) leave the province's growth below the national average. In the low case, British Columbia's real output grows at two percent annually over 1986 to 1990 and 2.1 percent on average from 1990 to 2005. In the high case growth averages 2.2 and 2.6 percent respectively.

While our high and low cases cover a fairly wide range of growth, we recognize that each projection is a point estimate of the relevant economic variables. There are many assumptions which could be different and which could widen the range of growth rates and/or change the composition of activity and have different effects on energy demand.

There are also other ways in which the aggregate growth rates - as established in our high and low cases - could be achieved: for example a different set of domestic and foreign policy assumptions could result in a different mix of goods and services output. As well, changes in national and international government policies on energy use - as discussed in the introduction to Chapter 4 - could have major impacts on energy use, the role of energy in the economy and the configuration of economic growth. Some of the implications of alternative economic assumptions for energy demand are discussed in Chapter 4.

As is the case for world oil prices, our economic growth projections are meant to portray sustainable trends in each case. We have not attempted to estimate business cycles. We recognize that growth rates will likely fluctuate above and below our projections; our purpose, however, is to estimate the longer run implications for energy demand of higher or lower long-run economic performance.

Chapter 3

Natural Gas and Electricity Prices

This chapter sets out how we determined natural gas and electricity prices.

3.1 Natural Gas Prices

Between 1975 and 1986 the price of natural gas in Canada was regulated. Because oil and natural gas are close substitutes in many end uses, natural gas prices were set at some percentage of the oil price at the Toronto city gate. The value of the percentage varied according to policy intentions and changing energy market conditions. For example, in the early 1980s substitution of gas for oil was encouraged with a relatively low percentage. Thus, given the oil price and the predetermined relationship between gas and oil prices, the price of gas was determined.

The October 1985 agreement on natural gas markets and prices[1] ushered in a return to negotiated natural gas pricing.

We drafted the October 1986 Report at the outset of the new policy environment and assumed, as a working hypothesis, that the price of natural gas would maintain a fixed relationship with the oil price. As mentioned in Chapter One, we found that linking the price of gas to the price of oil caused adjustment problems in natural gas markets. Oil is generally the closest substitute for natural gas. However, the price of oil is determined by international supply and demand factors beyond Canada's control, while the price of natural gas in Canada must reflect demand for Canadian gas (domestic and export) and the incremental costs of making it available.

With gas and oil prices linked, the oil price - hence the gas price - will not necessarily be low enough to reduce gas supply and increase demand when the gas market is oversupplied, nor will it necessarily be high enough to compensate producers for the replacement cost of natural gas when markets may no longer be over-supplied with relatively inexpensive natural gas reserves. We found that with a fixed gas:oil price linkage, in a high oil price environment natural gas markets remained over-supplied for an unrealistically long time, while in a low oil price environment, late in the 1990s demand exceeded the supply which could be made available at those prices. We mentioned in the October 1986 Report that this situation could not persist and that further market adjustment would have to occur.

In this report, we pursue this adjustment process, which requires that we make no *a priori* assumption of a gas:oil price linkage. Rather, as is the case for most other goods and services, the price of natural gas is determined by supply and demand conditions for natural gas. These conditions can generate a price path for gas which departs from that of oil. This is not to deny that the oil price influences the gas price: competition from oil in the fuel-switchable market is a major factor, among others, influencing demand for gas. Taking this into account, a viable price path for natural gas must balance supply and demand (domestic plus export) for gas over the long term.

Over the first several years of our projections, there will not be a balance, because we have surplus deliverability of natural gas which will take some time to be dissipated, even with relatively low prices and strong domestic and export demand.

Exports are an important factor influencing the price of natural gas because about one-third of Canadian production goes to the export market. As explained in Chapter One, given the basic policy thrust that markets should determine the allocation of resources, provided that markets are functioning competitively, we estimate what the market-determined export volumes of natural gas would be over the study period by finding those levels of gas exports which are viable in the U.S. market, and which result in domestic prices at which the supply and total demand for Canadian gas are about in balance.

---

1. *Agreement among the Governments of Canada, Alberta, British Columbia and Saskatchewan on Natural Gas Markets and Prices*, 31 October 1985.

In the following paragraphs we describe the main supply and demand factors which are important in determining the price of natural gas. On the supply side, these include the exhaustibility of the resource, its increasing incremental cost of production with cumulative reserves additions, user costs, transportation and distribution costs. On the demand side, the main factors include consumer response to changes in the prices of gas and alternative fuels (conservation and substitution), service requirements (e.g. firm versus interruptible, long-term versus short-term supply assurance) and gas exports.

We discuss these factors beginning at the wellhead with supply, continuing with transportation and then demand. We then describe some current institutional and commercial factors in the natural gas market which are relevant to making price projections at this time. We conclude with our high and low case price projections, discussing how we handle these supply, demand and institutional factors in the particular conditions of each oil price case.

Key Supply Factors Influencing Price[1]

- Natural gas is an exhaustible resource. As cumulative reserves and production grow, further discovery and development becomes more expensive per unit supplied, because an increasing amount of drilling will be required per unit of gas found; once found, the pools may have less and less favourable locations or producibility characteristics. Hence gas replacement costs increase with cumulative consumption. Technological progress in finding, developing and producing gas may mitigate the rate of cost increase. The implication of increasing real cost is that, over the long run, incremental supply requires that prices increase sufficiently to recover the incremental costs of that supply, including the producer's rate of return to capital employed in exploration, development, inventory and production.
- Apart from producer direct costs of exploration, development, inventory and production, there is another component to the current value of natural gas which is particular to exhaustible natural resources. It is commonly known as a "user cost". Two factors give rise to the user cost. Firstly, the resource is the resource-owner's wealth; as that resource is consumed, the wealth base is diminishing, and all else equal, future earning potential from that resource is thereby diminishing. Secondly, the future value of the resource may be greater than its present value; this future value is determined by either the future cost of gas, or the future price of its most economic substitute fuel, whichever is less.

The resource may be put on the market now, or held in the ground until a later time. The resource owner wishes to earn the full economic present value of the resource, taking account of its exhaustibility and future value. The "user cost" at any time is the difference in present value between selling the next unit of gas in the future rather than selling it now. It is a valid component of the price for today's gas, because it compensates the resource owner for selling the gas today rather than holding it in the ground until it becomes more valuable at some future date. In Canada, the major resource owners are the provincial governments.

It is reasonable to expect resource owners (i.e. provinces) to wish to recover the user cost in royalties, therefore we use our calculation of user cost as a proxy for royalties. The user cost is separate from and additional to the producer's rate of return to capital employed in gas supply.

- Producing provinces regulate the removal of gas from their provinces. The gas price is important to them because it affects the achievable level of royalties, land payments and other provincial revenues. Without engaging in gas price control, they can set royalties at rates which make it attractive or unattractive for producers to sell gas, depending upon the prices they can negotiate with their customers.
- The transportation of natural gas from producer to consumer requires a pipeline infrastructure for gathering the gas from the wellheads, transmitting it to local distributors, and distributing it to end use customers. In Canada,

---

1. There are several stages of natural gas prices:
   (i) fieldgate price: the price of gas before it goes into any transmission system (including intra-provincial systems). We include royalties at this stage.
   (ii) wholesale or city-gate price: the wellhead price plus all transmission charges up to the point where a local distributor receives it for onward distribution to consumers.
   (iii) retail price: the wholesale price plus local distribution charges.

   The distinction between the "gas price" and the "retail or wholesale gas price" is that the former refers only to the commodity - natural gas - in marketable form, while the latter includes delivery charges.

transportation facilities are regulated monopolies. Rate regulation is generally based on the cost of service, and these costs constitute a large share of the delivered price of gas. The more gas that can be shipped over a given system size, the lower the unit cost of transportation. Because of this large transportation cost wedge between the wellhead and the end user, relatively small percentage changes in retail gas prices become much larger percentage changes of wellhead prices. While gas prices now change largely according to market conditions, delivery charges are relatively stable.

Key Demand Factors Influencing Gas Prices and Size of the Gas Market

- The character and extent of fuel substitutability is a factor determining gas prices and the size of the gas market.

- Different end users have different ability and incentive to substitute between natural gas and other fuels. Most residential consumers using gas could heat their homes and water with light fuel oil or electricity, but substituting one fuel for another requires re-equipping the household. The same applies to some commercial and institutional buildings, but others have the capability to switch between fuel oil and gas at relatively low cost. While some industries need natural gas as an essential input to a production process, many others may switch to heavy fuel oil for heat and steam-raising with little difficulty.

- In that market sector which is readily switchable between gas and heavy fuel oil, substitution against gas will occur when gas prices rise only a little above parity with heavy fuel oil. In other market sectors, the gas price would have to rise above parity with (costlier) light oil or electricity before substitution against gas would occur. Where switching capability does not already exist, the extent to which the gas price must exceed the price of the competing fuel to induce switching differs between users, depending upon how costly it is for each to switch and how quickly they require pay-back of the conversion investment.

- The larger the proportion of the market which can switch fuels readily, the less the gas price must change to rebalance demand and supply when market conditions change. For example, if supply conditions deteriorated pushing gas prices up, the more of the market ready to switch, say, between gas and heavy fuel oil on the basis of a relatively small price differential between them, the less the gas price increase needed to release a given gas volume from lower to higher value use, and the smaller the price change at which the market rebalances to the tighter supply conditions.

- Fuel substitution capability is not static. Even where fuel substitution is relatively costly, the more time one allows for change to occur, and the larger and more durable the economic incentive to change, the greater is the potential substitution between gas and other fuels.

- In a falling or low oil price environment, there is a point below which decreasing gas prices will stimulate demand very little: consumers need only so much heat, alternative fuels are already unattractive, or the price differential between them and natural gas is already large enough to accommodate most of the conversions likely to be economic over some reasonable time period.

- While every unit of natural gas may give the same amount of heat, the conditions of gas service which consumers demand may be differentiated, and there are potentially different costs attributable to different kinds of service. For example, customers who wish firm guarantees now for gas supply far into the future may impose higher exploration and inventory costs on producers than would those customers who do not wish these guarantees. This could differentiate the price of gas. Customers who need much gas for some months of the year and little during the rest of the year impose higher unit costs on pipeline and distribution systems than those who have a steadier year-round demand. This differentiates delivery costs. To an extent, production and transmission cost differentials can be mitigated by co-mingling a broad variety of service requirements in production and transmission arrangements. But, distribution rates between, say, residential and large industrial customers are very different because there are sharply different and separated costs of servicing them.

- Exports have an impact on the shape of Canadian gas prices over time, because all else equal the greater they are, the greater the call on supply and the sooner the cost of supplying gas increases. Given the current market-oriented trade policy context, it is appropriate to project exports from a market-oriented perspective. Hence,

we view North American gas markets as a collection of interconnected regions producing and purchasing gas. Gas moves between regions in a way that minimizes costs to consumers and maximizes returns to producers, taking account of relative supply and transportation costs between alternative sources and consumers. This process determines exports. It is described more fully in Section 6.5 where we discuss the export projections consistent with the prices described here.

- The main constraints to exports are: pipeline capacity (which can be expanded at a cost), competing supplies of gas and oil in the U.S. market, and most importantly, the requirement that the sum of Canadian domestic and export demand for Canadian gas not push Canadian wholesale gas prices above comparable U.S. prices. If it did, Canadian gas would not be competitive in the U.S., and export activity would fall back to the level at which Canadian prices and exports were in balance relative to Canadian demand, supply and U.S. market conditions.

- Gas prices available in the export market will not necessarily determine gas prices in Canada, but they will certainly influence them. If there were no constraints on trading conditions, when U.S. gas is cheaper than Canadian gas, Canadian consumers would bid down Canadian prices till they met the competition from imported gas; when U.S. prices are higher than Canadian prices, producers would divert supply to the U.S. unless Canadian consumers were prepared to match netbacks available on sales to the U.S. Several factors, however, can prevent this process from fully equalizing comparable prices between the two countries. Firstly, pipeline constraints and contractural rigidities can prevent high enough volumes from switching markets to fully re-align prices. Secondly, when Canadian exports are pushing prices upward, the highest prices Canadian consumers are willing to pay may be less than those U.S. consumers would pay if alternative fuel costs were lower in Canadian than in competing U.S. markets; when imports are pulling prices downward, eventually the lowest prices Canadian producers will accept must recover at least the replacement cost of gas and user costs. These costs could exceed prices temporarily available in the U.S. Thirdly, different service conditions can imply differences in costs and prices. Service mixes may not be the same between domestic and export sales. (This makes it important, when making price comparisons, to compare service arrangements which have similar cost implications.)

Current Market Conditions

In designing our approach to gas price behaviour for this report, we also had to consider a number of factors which presently characterize the Canadian gas market.

- On an annual basis, there is surplus productive capacity relative to demand in both Canada and the U.S. Canada's surplus is unlikely to be eliminated until the early 1990s, and there is much uncertainty about when the U.S. surplus will be eroded. Excess supply exerts downward pressure on prices and delays the time at which reserves additions will be needed.

- The surplus does not mean that the wellhead price of gas will be competed down to the current operating cost of producing gas from connected reserves, which may be currently about $C 0.60 to 0.70 per gigajoule: firstly, the gas has future value justifying a "user charge" which the resource owners wish to collect; secondly, producers wish to recover what they can of capital costs previously incurred; thirdly, for Alberta gas, the interest charges on take-or-pay liabilities must be met; finally, as we mentioned above, there is some price below which further price reduction would have virtually no impact on demand. Producer provinces may influence the terms and conditions under which gas leaves provincial boundaries, given their authority over removal permits and royalties.

- Over the past two years, the major "system supply" contracts between TransCanada PipeLines (TransCanada) and distributors in central and eastern Canada have provided for different discounts to different customer classes relative to a base price of gas at the Alberta border. This results in very different retail gas prices to residential consumers on the one hand and certain industrial customers on the other. For example, discounts to residential consumers in Ontario are of the order of $C 0.40 per gigajoule while those to certain industries exceed $C 1.00 per gigajoule, relative to a base price of $C 2.79 per gigajoule at the Alberta border.

- This kind of differential discounting, also known as "price streaming" has been sustainable because a high proportion of the

supply to central and eastern Canadian distributors is under contract with TransCanada. The streaming has contributed to preserving the size of the gas market and to mitigating the decline in producer netbacks at a time when oil prices have been low. Residential customers still pay less for gas than they would for light fuel oil or electricity in similar use. Given the large industrial discount, the average per unit netback to the producer for all gas sold is below the incremental gas supply costs (replacement costs) which we estimate in Figure 6-4 of Section 6.3, but above the cost of producing existing reserves.

The streaming of discounts has raised a general matter of principle as to why different consumers should pay different prices for the same commodity. Streaming has been occurring over the past two years of negotiated natural gas pricing, and the question facing our analysis is whether to assume that it continues. We deal with it differently in the low and the high cases.

- Streaming has offsetting impacts on the less-switchable gas market. Relative to a given unit wholesale revenue requirement averaged across all users, when switchable customers pay less than the average price for their gas, the primary impact is that the less-switchable (more captive) ones must pay more than the average.

However, if this prevents the switchable customers from leaving the gas market, it has the secondary, beneficial impact on the more captive ones of stabilizing their transmission and distribution costs. This happens because transmission and distribution total revenue requirements are about the same regardless of the volume of gas sales (given regulated recovery of costs associated with the historical rate base); hence, the smaller the sales volume, the higher these charges per gigajoule of gas which remaining customers must pay. An interesting question, which we examine, is the extent to which the more captive customers would pay more or less for their delivered gas with and without streaming. This depends upon the relative size of the primary and secondary impacts identified above.

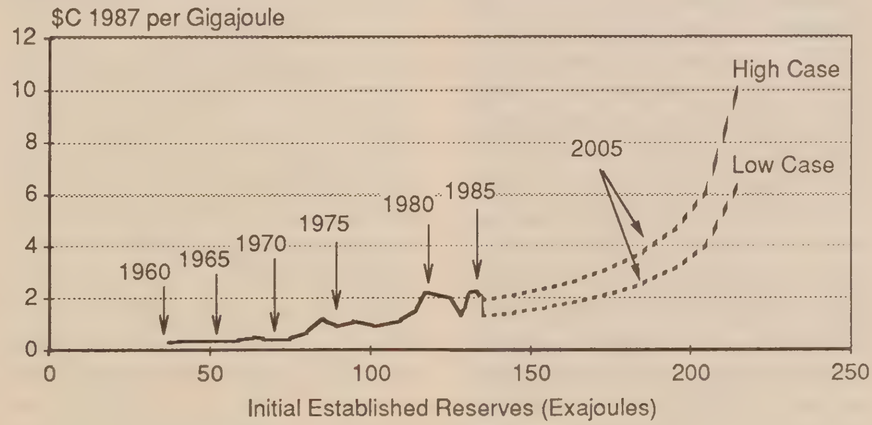
Process for Determining Natural Gas Price Paths

Our approach to determining gas prices is to use analysis of the supply and demand factors noted above in order to find price paths which approximately balance demand (domestic and export) and supply in each year of the study period. To do this, we make use of four models: the NEB energy demand, gas deliverability and supply costing models, and the "North American Regional Gas Model"[1] - the last one for estimating export demand. We use these models jointly to obtain approximately balanced projections of supply, domestic consumption, exports, and prices over the study period.

Figure 3-1 shows the supply curves for Canadian natural gas, that is the amount of gas which can be supplied at different levels of incremental wellhead cost, in each case. Section 6.3 contains a detailed discussion of how these curves are developed. The supply cost is lower in the low case than in the high for reasons discussed below in our exposition of the low case price projection.

1. Property of Decision Focus Inc., Los Altos, California

Figure 3-1
Net Incremental Direct Costs For Natural Gas



We begin the price determination process with a preliminary Canadian primary demand projection for natural gas, a corresponding price projection, and a preliminary export projection developed from the North American Regional Gas Model. The sum of these demands is input to the supply costing model, which develops annual rates of reserves additions, productive capacities and resulting supply costs per gigajoule incurred to meet this demand, based on the supply curves of Figure 3-1. By adding transportation and regional distribution costs to the wellhead supply costs, a set of regional end-use prices emerges, which differs from the retail prices underlying the preliminary demand projection. Let us say they are higher.

These higher prices are put into the demand model, out of which comes a new lower demand projection. The reduced demand is input to the supply model; it will then calculate a reduced cost path, compared with the previous one which satisfied a higher demand.

After several iterations of this kind, further iterations produce very little movement of demand, costs and price, meaning that the market is in approximate balance. The new Canadian demand profile is input to the export model, which finds the export level competitive in the U.S., taking account of Canadian supply and demand conditions.

Wellhead gas price paths emerging from this process are shown in Table 3-1 and Figure 3-2. The price paths differ between the low and the high scenarios because demand and supply conditions differ as explained immediately below. The prices do not meet gas replacement costs in the early years of the study period, because there is a surplus of productive capacity. Confronted with a large surplus of productive capacity, the gas market balances only after several years, because even with lower prices, demand does not increase, and reserve additions do not decrease, quickly enough to work off the surplus in the short term.

Table 3-1

Alberta Fieldgate Natural Gas Prices

($C 1987/GJ)

	Low Case	High Case
1986	2.11	2.11
1987	1.55	1.55
1990	1.58	1.68
1995	2.05	2.75
2000	2.60	3.61
2005	3.32	4.62

Because the market does not balance over the first several years of the projection, and because there are factors (discussed above) preventing the price of gas from falling as low as the level of variable production cost, it was necessary for us to exercise judgement in developing a price projection for the first several years of the study period. The main factors which we used in developing these prices are:

(i) prices should be sufficient to recover production costs, user costs, take or pay liabilities, transportation and distribution costs;

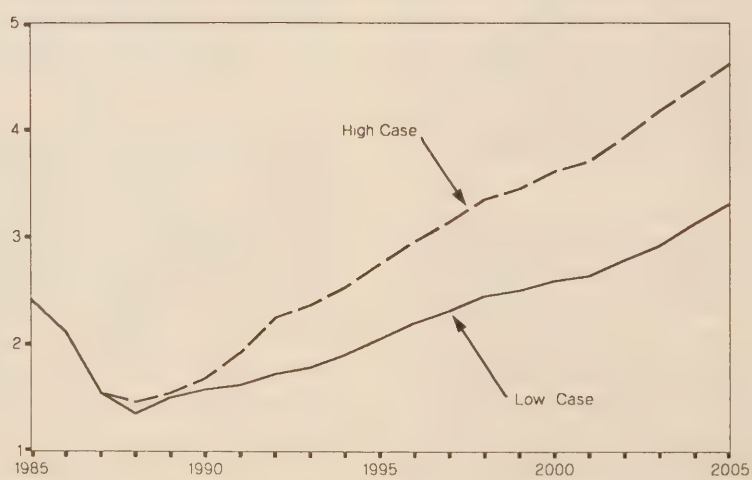
(ii) the streaming of different prices to different consuming sectors should be reduced to the point where prices reflect only differences in real costs of meeting different service requirements;

(iii) if the reduction of streaming and the maintenance of the unit revenue requirement in (i) above would result in a gas

Figure 3-2

Fieldgate Natural Gas Prices Low and High Cases

($C 1987/GJ)

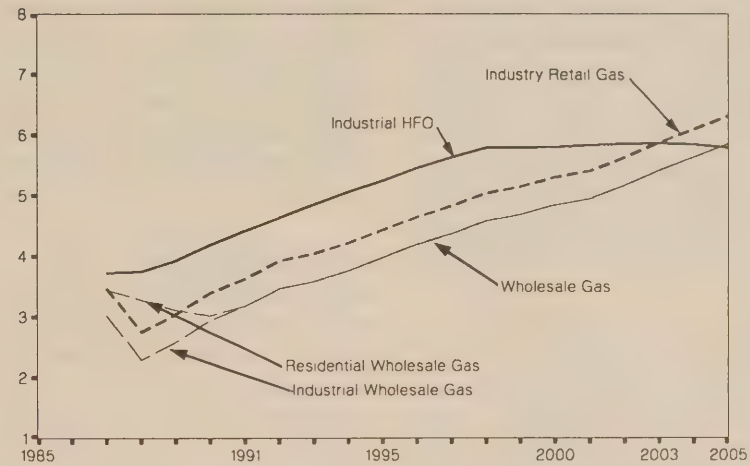


price uncompetitive with oil in the switchable market, we assume that there would be an effort to maintain streaming, as long as this does not cause the more captive customers to pay much more than they would without streaming;

(iv) the oil price is the key factor influencing the incentive to stream gas prices, because it is the main competition to gas in the switchable market; therefore, even though the oil price does not determine gas prices, it influences them, and we must have regard to the impact of the oil price in determining natural gas prices.

Figure 3-3
Comparative Energy Prices - Ontario High Case

($C 1987/GJ)



High Case Gas Prices

We do not know what will happen to contractual arrangements between TransCanada and the major distributors east of Saskatchewan for the 1988-89 gas year and beyond. Therefore we base gas prices in the early years of the study period on the premises that:

- it is reasonable to start the projection on the basis of today's contractual arrangements and prices, which include streaming, and in which natural gas prices are below the price of heavy fuel oil in the industrial sector (except in Quebec) and below the prices of competing fuels in the other sectors;
- streaming will be of decreasing importance to producers as the oil price (hence the value of gas in switchable markets) increases;
- until the gas surplus erodes there will be downward pressure on gas prices; thus at the wellhead, producers receive prices below reserve replacement costs, but above the operating cost of producing connected reserves.

Hence, we keep the residential and commercial wholesale gas price unchanged in nominal dollars (i.e. it falls in real terms by an amount reflecting the rate of inflation), and we allow the industrial wholesale gas price to increase at a rate slightly greater than the rate at which the heavy fuel oil price increases. (We assume that heavy fuel oil is priced at 90 percent of the crude oil price.) With the residential and commercial wholesale gas price fixed and the industrial wholesale price increasing, these different sectoral gas prices converge into one wholesale price. In Ontario, this happens by 1991. This single wholesale price continues to increase, but when netted back to the wellhead, is still below the replacement cost of gas till 1994, because the gas market is still in surplus. The surplus is virtually eroded by 1994, by which time the gas price fully reflects the replacement cost of gas.

From 1994 onward, with the wellhead price increasing at the rate of replacement cost increase, the Ontario wholesale gas price path remains below the heavy fuel oil price till 2005. By 2003, growth in the replacement cost of gas has reached the point whereby the industrial retail gas price in Ontario exceeds the heavy fuel oil price, hence the industrial retail gas price "decouples" from and exceeds the heavy fuel oil price from that time onward, reaching about 10 percent above the heavy fuel oil price by 2005. Figure 3-3 shows the development of the wholesale gas price path, as described above.

There are some variations between provinces in this general approach to gas prices in the high case, reflecting varying provincial market characteristics and policies.

In Quebec, the ratios of gas prices to oil prices are, in general, moder-

ately above those of Ontario. This happens because the service mix of gas in Quebec is different from Ontario's, resulting in a gas price slightly higher than that in Ontario. Furthermore, Quebec distribution margins exceed those in Ontario. This is so, even though for the first 40 petajoules of gas demand growth in Quebec, we have increased nominal distribution costs by only one-half the general rate of inflation, given current excess distribution capacity in Quebec.

In Manitoba, the method of price determination is similar to that shown for Ontario; however, base year price differences between the two provinces are preserved over the study period.

In Saskatchewan, the wholesale gas price increases from current levels at the same rate as the Alberta border price,[1] or the rate shown in Figure 3-3. There is no price streaming in Saskatchewan throughout the study period.

In Alberta, the wholesale gas price is linked to the border price by a ratio, which stood at 0.65 under the intra-Alberta sales subsidy program, now being phased out. To reflect this, we increased the ratio gradually to reach 1.0 by 1991. We assume no internal price streaming.

For British Columbia, we assume that the wholesale price increases at the same rate as the Alberta border price over the study period. There is price streaming between market sectors in 1988 and 1989, phasing out as described above for eastern Canada.

Retail prices by province and by sector are in Appendix Table A4-1.

Low Case Gas Prices

The low case presents serious difficulties for the remunerative pricing of natural gas, because the oil price is very low relative to the incremental cost of supplying natural gas. For example, Figure 3-4 shows the relationship between the price of heavy fuel oil, and the price of gas to Ontario's industrial sector based on the replacement cost of gas.

In this scenario, if all gas were sold at its replacement cost, there would be substantial erosion of the gas market, (about 615 petajoules for Canada by 2005), as all users for whom it is economic to switch to oil would do so, and the gas market would be confined to its higher value uses. There would be upward pressure on transmission and distribution costs, roughly in proportion to the rate of shrinkage of volumes transported. Increased delivery cost could cause the gas market to shrink further. This is clearly one way in which the gas market could function. We call it the "no-streaming" approach.

However, we believe that an alternative approach is at least as likely in a low oil price environment: faced with a long-term prospect of low oil prices, as in our low case, the gas industry and producing provinces could take measures to preserve the natural gas share of the energy market. These measures would amount to a set of compromises made by all involved in the production, delivery and use of gas. There are a number of possibilities. One such scenario is the following.

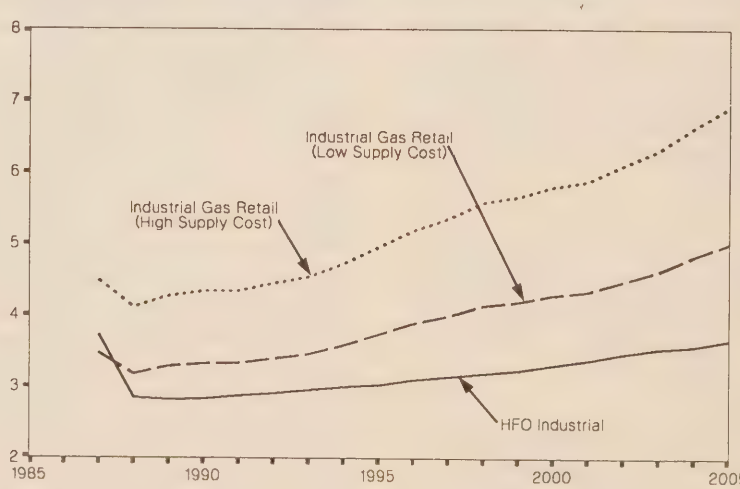
Firstly, in the economic environment of the low case, producers accept a lower rate of return to capital than they otherwise would. As explained in Chapter 6, we reduce the real discount rate on all capital employed from 15 percent in the high case to 10 percent in the low.

1. The Alberta Border Price is a conceptual price reflecting unit revenues from all sales of Alberta gas, net of transportation charges between the market and the Alberta border.

Figure 3-4

Natural Gas and Oil Prices - Ontario
Low Oil Prices; No Streaming of Gas Prices

($C 1987/GJ)



Secondly, given the poor environment for the gas and petroleum industries, input costs to these industries are driven down relative to high case levels, as described in Chapter 6. This decrease relates especially to drilling costs; it reduces the supply cost of gas.

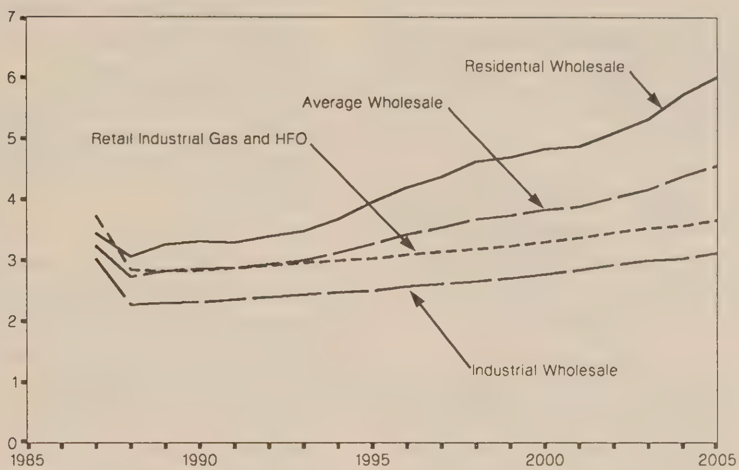
Thirdly, consumers accept that there will be continued streaming of gas prices, as now occurs (rather than the convergence of wholesale prices rendered feasible by high oil prices in the high case). This means that the readily-switchable market is preserved by charging it gas prices related to the heavy fuel oil price, while the remainder of the market pays higher prices, such that when combined at the wholesale level and taken back to the wellhead, the average price received for the gas is sufficient to cover the (reduced) replacement cost. Because the gas replacement cost is reduced relative to that of the high case, the amount charged the less-switchable market is either below their alternative energy costs (usually light fuel oil or electricity) or not enough above it to make switching worthwhile.

In the low case, as in the high, wellhead gas prices are below incremental gas replacement costs until the gas surplus erodes by about 1994. From then onward, wellhead gas prices reflect incremental replacement costs. There is retail price streaming in all provincial gas markets. Internal wholesale gas prices in Manitoba, Saskatchewan, Alberta and British Columbia increase from their current levels at the same rate as the Alberta border price. Figure 3-5 illustrates the pattern of this pricing outcome. Retail prices by province and by sector are in Appendix Table A4-1.

Figure 3-5

Natural Gas Pricing - Ontario Low Case

($C 1987/GJ)



In the economic conditions of the low case, the regulated pipeline rate of return may be reduced, causing transportation tolls to be reduced. We have not introduced this assumption in our low case scenario. Had we done so, the extent of streaming necessary to maintain the size of the gas market would be reduced, or the cost to producers of a no-streaming scenario would be less.

The conditions necessary for streaming to be viable are that:

- provincial regulatory policies allow different categories of consumers to be charged different prices for gas, and
- producer provinces or marketers can exercise enough control over the buying and selling of gas to segment the gas market such that different prices can be maintained for different categories of customers.

We use the "streaming" approach because it reflects current experience, there are provincial jurisdictions for whom it is acceptable, natural gas remains generally advantageous for residential consumers, and even with some competitive marketing, there could be ongoing price differentiation between consumer categories based on differentiated terms and conditions of contracts designed to meet their particular needs. By using the "streaming" approach we have chosen to represent a pricing arrangement which tests for the largest likely size of the domestic gas market under these oil price conditions. We recognize that this approach departs from competitive conditions. By illustrating its application here, we are neither recommending it over the "no streaming" approach, nor are we suggesting its inevitability.

We recognize that there are jurisdictions for whom it may be unacceptable to maintain gas price differentials between customer classes, and that the state of competition in gas marketing could evolve to the point where gas price

differentials would be unsustainable: marketers could buy gas from the cheapest sources of supply and resell it to any taker.

We examined the impact of the "no streaming" approach on the Quebec and Ontario natural gas markets, and found that by the end of the study period:

- the industrial retail natural gas price would exceed the heavy fuel oil price by about 52 percent and 40 percent in Quebec and Ontario respectively;

- natural gas demand would be 540 petajoules below the low case total gas demand (with streaming) of about 1300 petajoules (a reduction of approximately 40 percent); this reflects a loss of about 85 percent to 90 percent of the low case industrial gas market in these two provinces (for all of Canada, the demand reduction is 615 petajoules, or a 25 percent reduction of low case total gas market size);

- In Quebec, the "no streaming" scenario results in residential and commercial natural gas prices increasing by about 2.5 percent and 9 percent respectively relative to those of the low case with streaming; this happens because in Quebec, the industrial load loss is large relative to the size of the residential and commercial markets, hence the latter absorb increases of unit delivery cost which more than offset the reduction of the wholesale gas price to them;

- In Ontario, residential consumers enjoy about 6.5 percent lower gas prices without streaming, while for commercial consumers prices remain the same; this happens because Ontario has a large residential market, and the industrial load loss is a relatively smaller part of the residential market (in comparison to Quebec); the additional delivery cost incurred without streaming is less than the wholesale gas price reduction for residential customers, while these two factors virtually offset each other for commercial customers.

In sum, had we adopted the no streaming approach, the size of the domestic gas market would be about 25 percent smaller, and wellhead prices would be lower, because there would be less cumulative reserves additions. This could have the effect of increasing exports relative to those of the low case with streaming, because a comparatively larger volume of lower cost Canadian gas could be made available. If exports increased, wellhead prices would then increase again, as required by the increased call on the Canadian resource.

Institutional and market forces will determine the specific structure of natural gas prices in ways which may well differ from either of the approaches we have described in this report. The most important general conclusion, however, is that a low oil price environment imposes difficult options for the natural gas market, be it in respect of market size or pricing behaviour, provided that natural gas replacement costs are roughly of the shape we estimate in Figure 3-1.

3.2 Electricity Prices

In past reports we assumed that electricity prices would remain constant in real terms throughout our projection period. These prices (and other factors) determined electricity demand, which was used, in turn, to derive the corresponding required increments to generating capacity and associated fuel requirements for electricity generation.

Since completing our 1986 report, we have developed an analytical framework which allows us to calculate revenue requirements needed to meet utilities' stated financial targets, for a specific generation/demand profile. With this methodology, we can iterate between the supply and demand for electricity to determine a price path which meets the utilities' financial objectives and is consistent with both supply and demand profiles.

The basic elements of our framework are: a demand model (in which electricity prices influence demand); a supply model (which determines capacity additions and fuel requirements to meet demand); a capital cost calculator (which estimates capital costs of the capacity additions) and an electricity financial module (which uses the above information to derive a price path which meets stated financial objectives). The calculated price is re-introduced in the demand model, in our iterative approach, until supply and demand converge at a common price.

This approach to price determination approximates electricity price setting practices. Where utilities use stabilization funds to avoid rate shocks as new plants enter the rate base, our framework portrays this arrangement.

The basic pricing policies of utilities, for a given set of financial targets, result in periods of declining real or even nominal prices when there is little construction activity, but increasing real prices as new plant is brought into service. However, utilities or

regulators may alter financial targets and maintain price increases during periods of anticipated price declines in order to meet other objectives, such as enhanced energy conservation, increased dividends to shareholders, or increased internal cash generation for future facilities expansion.

Table 3-2 shows, for each of the high and low cases, the growth in electricity prices required to meet utilities' current stated financial objectives, using generation profiles consistent with our high and low cases and our assumptions of capital and operating costs, interest rates and other economic variables. These growth rates incorporate announced price changes for the next few years, as indicated by utilities, and the estimated cost of demand management for Ontario Hydro and B.C. Hydro, as discussed below.

Table 3-2 also shows the growth in electricity prices assuming that increases track the rate of inflation, after including announced price changes over the next several years.

Table 3-2

Electricity Price Growth

1987-2005

Average Annual Growth Rates (Percent)

	Low Case		High Case	
	Inflation[a]	Revenue Requirements[b]	Inflation[a]	Revenue Requirements[b]
Atlantic	4.2	3.3	4.7	4.6
Quebec	4.3	3.2	4.8	4.3
Ontario	4.4	2.0	4.8	2.5
Manitoba	4.3	3.6	4.8	3.2
Saskatchewan	4.4	1.6	4.9	2.1
Alberta	4.4	3.3	4.8	3.9
British Columbia	4.4	1.5	4.8	3.2

Notes: [a] Announced price increases after which price growth tracks inflation.
[b] Announced price increases after which price growth is calculated to meet current stated financial objectives and corresponding revenue requirements.

The Issues

Over the past decade some utilities have been in positions of surplus capacity and have introduced incentive programs to sell this surplus to specific users. The most notable example has been Hydro-Québec's incentives to the industrial sector.

Most utilities increasingly perceive that over the next decade supply and demand will be in much closer balance, and that capacity additions will be needed to maintain that balance. Utilities in some provinces are reviewing a variety of options to deal with the need for additional capacity. New demand management programs are being actively considered by some utilities, notably Ontario Hydro and B.C. Hydro, where such measures would be cost-effective as compared with the cost of new capacity. These programs contemplate incentives being offered to specific users to improve the efficiency of their electricity use. These incentives would be financed by the utility and would result in rate increases less than would have been required had there been capacity additions.

Utilities are also considering load management techniques, such as time-of-use rates, which would reduce peak requirements. These innovations in rate design and other incentives for improved efficiency in the use of electricity are clearly designed to delay the timing or reduce the amount of new generating capacity requirements. Having implemented these programs, the resulting revenue requirements may be low enough to yield declining electricity prices if they were determined solely on a cost of service basis. However, the utilities may choose to stabilize electricity prices rather than allowing them to decline, as the latter option may encourage higher consumption, contrary to the intention of their load management and conservation programs.

As well, certain utilities have been required to distribute some or all of their financial surpluses to shareholders, rather than apply them against future requirements or return them to customers in the form of price reductions. We expect this practice to continue.

In developing our approach to electricity pricing for this report, we consulted with major Canadian utilities regarding their outlook for electricity pricing. Most utilities agreed that, although existing financial objectives and standard accounting practices would suggest declining real prices for some period of time, the factors discussed above could lead to price growth more in line with the general rate of inflation. Some utilities,

B.C. Hydro in particular, argued that over the medium term electricity price growth would nonetheless remain below the rate of inflation.

However, following our consultations, we feel that there are several areas of uncertainty which could lead to price increases above those indicated by utilities' current stated financial targets. These include:

- the treatment of the distribution of financial surplus and the return to shareholders;
- the role and size of export revenues, which are currently included in utilities' revenues for determining domestic prices;
- uncertainties over costs of future expansions;
- upgrading of transmission and distribution systems;
- delays in approval of new capacity;
- environmental concerns; and
- changes to existing financial targets.

These factors have led us to assume electricity prices will increase with the general rate of inflation. We have used our new methodology to verify that the resulting prices will at least meet the current financial targets of the utilities. As seen in Table 3-2, our prices exceed those calculated to meet existing revenue requirements.

Chapter 4

Energy Demand

In this chapter, we examine end use energy demand by sector and by fuel. For each major energy form, we follow demand from end use to primary requirements. End use requirements include space and water heating, motive power for equipment, appliances and vehicles and process fuel for industries. To arrive at the amount of primary energy required, we add to end use demand the fuel and losses associated with the production and distribution of each energy form.

During the past fifteen years Canada and other industrial countries have experienced massive changes in energy use. With the rapid increases in oil prices of the 1970s and the expectation that such increases would continue into the future, major efforts were made to improve the energy efficiency of capital and to implement policies which would reduce energy demands. During the early 1980s Canada experienced an absolute decline in end use demand, which resulted partly from major improvements in automobile fuel efficiencies and from explicit conservation measures in all sectors, as well as from the 1982 recession, which led to a substantial decline in economic output. With economic recovery, end use demand has been increasing, although energy intensity (end use energy demand per dollar of output) continues to decline (Figure 4-1).

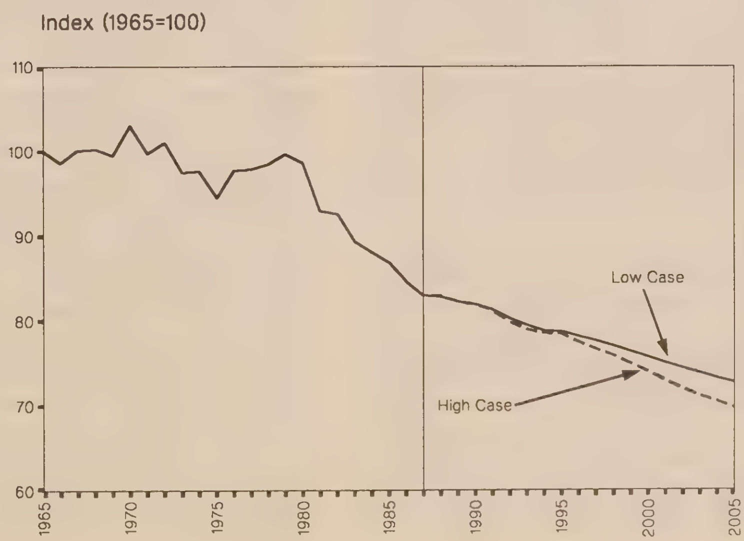
Energy demand is a derived demand. That is, energy is needed to perform another function, such as space heating, powering motors for industrial processes or automobiles for transportation. How efficiently energy is used depends, among other things, on the characteristics of the capital equipment which consumes the energy, for example, the thermal efficiency of a house, furnace efficiency or automobile efficiency. Today's stock of energy using equipment differs greatly from that of the early 1970s. These efficiency improvements along with changes in consumer behaviour, such as more efficient driving habits and lower winter thermostat settings, contributed to the decline in energy intensity of almost 1.5 percent per year from 1976 to 1986.

A major issue in energy demand projections is the extent to which energy intensity will continue to decrease in the future. The price of oil is now well below its peak of the early 1980s. There is no longer the widely-held perception that oil prices will rise rapidly in real terms over the indefinite future. Industrial countries' reliance on oil has lessened substantially, and individual consumers in all sectors have experienced major reductions in their energy needs.

We do not anticipate a reversion to the much less efficient capital stock of the 1960s and 1970s. For example, it is not possible to buy a new car today with the energy-using characteristics of one built in the late 1960s or early 1970s. Appliances are all much more effi-

Figure 4-1

End Use Energy Demand per Unit of RDP



cient and in some regions legislation is being introduced which will mandate further efficiency improvements. Even if there were no further improvements in the energy efficiency of new equipment from today's levels, we would see decreases in the intensity of energy use at least over the medium term as older, less efficient capital stock is replaced.

Our projections (Figure 4-1) show continued improvements in energy efficiency, which contribute to average annual declines in energy intensity of 0.7 percent and 1 percent over the period 1986 to 2005, in the low and high cases respectively. These rates of improvement are below those experienced over the past decade, but we feel that they are well within the bounds of achievable gains using existing technologies.

The analysis regarding conservation and efficiency measures which underlie our energy intensity projections are detailed by sector below.

There are, of course, uncertainties relating to technological developments which might increase the rate of efficiency improvements of energy-using equipment and relating to attitudes of consumers and government, which could enhance or delay efficiency improvements. The impact on our end use projections of alternate views on energy efficiency is discussed in Section 4.4.

Environmental concerns have had major impacts on energy consumption. Automobile emission control standards and legislated automobile fuel efficiency standards in the United States are but one example. Very recently, however, discussion of environmental problems relating to energy has become widespread, resulting to a great extent from increased awareness on the part of the general public, following the 1987 report of the United Nations World Commission on Environment and Development (the Brundtland report). This report and the World Conference on the Changing Atmosphere (held in Toronto in July 1988) have warned of dramatic changes to the global environment over the next 50 to 100 years, which could have enormous consequences for every aspect of economic life on the planet.

Studies presented at the World Conference on the Changing Atmosphere claim that, if present trends continue, increasing carbon dioxide levels in the atmosphere could, through the greenhouse effect, raise the global mean temperature between 1.5 and 4.5 degrees Celsius over the next 50 years. The studies say that this would change weather patterns all over the globe; interiors of continents would tend to get drier, oceans may rise, winters would shorten while summers become longer and hotter.

A number of research studies sponsored by the Canadian Climate Impacts program have attempted to assess the socio-economic consequences for various regions of Canada of global warming. One study concludes that mean Great Lakes levels and mean flows in the connecting channels would be reduced, thus reducing hydroelectric generating capacity. Also, warmer weather could reduce residential heating requirements by 30 to 45 percent, while electricity demand for air conditioning units could rise by 7 percent. Another study projects a 7 to 20 percent increase in water supply to the James Bay basin as a result of increased ocean levels which would increase capacity for hydroelectric generation there. Other studies explore the consequences of the greenhouse effect for agriculture, forestry, Great Lakes shipping and recreation.

In the absence of world-wide action, the most dramatic effects of global warming will likely take place over the next 50 years; however, in order to slow the trend toward global warming, environmentalists insist that governments must take policy action soon. The World Conference on the Changing Atmosphere recommends that industrial countries reduce carbon dioxide emissions 20 percent by 2005.

If the government were to embrace this goal, relative to pricing structures and demand management programs in place today, it would require greater incentives to reduce the economy's reliance on fossil fuels via improved energy efficiency and greater development of alternative non-hydrocarbon energy sources. There are a wide variety of ways in which such objectives could be achieved. Price signals could be altered through the use of taxes and subsidies, or efficiency improvements could be legislated. Production processes may be altered, including the way in which we develop and harvest renewable resources such as agricultural crops, and the way in which we manage our forest resources. The extent to which these changes may occur, and the way in which they would be implemented is uncertain.

Such measures would greatly influence our supply and demand estimates. However, not enough analysis has been done on the subject, nor do we have sufficient information on how governments

world-wide will react to this challenge to incorporate these measures in our outlooks. The demand analysis in the remainder of this chapter largely assumes the continuation of present approaches to price formation, announced programs of demand management in the electric power sector, and energy efficiency improvements as discussed above.

4.1 End Use by Sector

4.1.1 End Use Energy Prices

End use prices are burner-tip prices paid by ultimate energy consumers. They include refinery, transportation and distribution margins, and taxes. In Chapter 2, we described how we arrived at our world oil price projections. In Chapter 3, we discussed the derivation of natural gas and electricity prices. In this section, we explain how end use prices are calculated for each of these fuels in each sector.

Because energy prices vary by fuel and by sector, as well as by region, it is difficult to draw specific conclusions based on national average prices by sector but some general trends do emerge in our two cases.

Table 4-1 presents average burner-tip energy prices in 1987 dollars by sector, for Canada, for the two cases. These prices were derived by weighting provincial or regional prices by each region's share of national demand. They are not adjusted for relative fuel efficiencies.[1]

For oil, end use price trends are quite different from the pattern for world oil prices described in Chapter 2. For example, in 1986 the Ontario residential price of light fuel oil was $C 7.55 per gigajoule as compared to $C 3.31 per gigajoule for crude oil in Edmonton. Refinery margins, transportation charges, distribution costs and taxes accounted for 56 percent of the burner-tip price, constituting a large wedge between the crude oil price and the price to end users. We assume that refinery margins, transportation and distribution costs increase at the rate of inflation throughout the projection period, while taxes remain at their most recent actual levels in real terms. Motor gasoline and diesel prices are calculated in the same way.

Differences in natural gas prices among consuming sectors were described in Chapter 3. As with crude oil and product prices, natural gas prices to end users have a different pattern of growth from fieldgate prices, due to the large proportion of transportation and distribution costs included in end use prices - particularly in the major eastern markets. These costs are assumed to increase at the rate of inflation in both cases.

As discussed in Chapter 3, in the high case over the long term, natural gas prices reflect incremental supply costs and all sectors pay the same wholesale price for natural gas. In the low case, industrial users pay the same price for natural

Table 4-1

Average Burner - Tip Energy Prices[a]

($C 1987/Gigajoule)

	1986	1990		2005	
		Low	High	Low	High
Residential					
Natural Gas	5.17	4.89	4.71	7.73	7.59
Light Fuel Oil	7.66	6.74	8.29	7.76	10.09
Electricity	13.07	13.17	13.08	13.15	13.09
Commercial					
Natural Gas	4.51	4.14	3.95	6.65	6.93
Light Fuel Oil	6.60	5.55	7.09	6.48	8.87
Electricity	16.49	16.61	16.50	16.66	16.57
Industrial					
Natural Gas	3.31	2.50	2.88	4.03	6.64
Heavy Fuel Oil	3.72	2.76	4.08	4.20	6.42
Electricity	9.06	9.29	9.29	10.98	10.76
Motor Gasoline (cars)	13.76	13.47	15.20	13.78	16.37
Crude Oil - Edmonton ($C 1987/cubic metre)	133.03	113.16	170.95	148.64	239.93

Note: [a] Prices are not adjusted for relative fuel efficiencies.

1. Adjusting for fuel efficiencies changes the level of fuel prices and potentially the rankings of prices of the different fuels. In fact, over our study period this fuel efficiency adjustment does not usually change price rankings. Efficiency-adjusted prices are shown in Appendix Table A4-1.

gas as for heavy fuel oil (on an efficiency adjusted basis). Because the heavy fuel oil price is below the replacement cost of gas in the low case, over the entire study period, residential and commercial natural gas consumers pay higher prices which, when averaged with the industrial price, result in a wellhead price equivalent to the incremental gas supply cost. This calculation resulted in natural gas prices to residential and commercial consumers in the low case which did not differ substantially from those in the high. Thus there is very little difference between the two cases in natural gas prices to the residential and commercial sectors, while industrial gas prices are higher in the high case than in the low (Table 4-1).

Electricity prices in the commercial and industrial sectors are actual levels through 1988. In the residential sector they reflect actual prices through 1987 only. For regions where information is available, we have used utilities' announced price increases to estimate prices for one or two years beyond the last year of historical data. Thereafter, for all regions and in both cases, we assume that end use electricity prices remain constant in real terms. The reasons for this assumption are discussed in Section 3.2. Electricity prices in each region are constant in real terms, but the national average price reflects changes in regional electricity use, and the weighted average may vary as a result.

Turning to prices in individual sectors, in the residential sector only the light fuel oil price differs appreciably between the high and low cases, natural gas and electricity prices are virtually the same, as discussed above. Since light fuel oil currently accounts for only twenty percent of residential end use demand and since this share declines in our projections, in most regions light fuel oil prices are not as important as other fuel prices in determining residential energy use.

Therefore the weighted residential energy price index (see Table 4-2) shows very similar real growth between the two cases. Relative energy prices in the residential sector, adjusted for the efficiencies of different fuels, appear in Appendix Table A4-1.

Average prices for the commercial sector show a similar pattern to that of residential prices. There is very little difference in natural gas or electricity prices between the two cases. The share of light and heavy fuel oil in commercial use is anticipated to decline from 12 percent in 1986 to about eight percent by 2005.

In the industrial sector, prices for the two cases differ more substantially. Although electricity prices are similar, natural gas and heavy oil prices reflect our specific assumptions concerning gas price streaming and our world oil price. Heavy fuel oil prices are assumed to track the crude oil price on a 90 percent equivalency basis. By 2005, the price of heavy fuel oil in the high case is 53 percent greater than in the low. Industrial natural gas prices in the Ontario market are below parity with heavy fuel oil prices (on an efficiency - adjusted basis) in the high case during most of the projection period, but increase more rapidly during the last four years to exceed heavy fuel oil by about eleven percent in 2005. In the low case, the natural gas price reaches parity with industrial heavy fuel oil early in the projection period and we assume that this relationship is maintained thereafter.

In Quebec, industrial natural gas prices are above those in Ontario, reflecting higher distribution costs. Over the past few years, the industrial natural gas price in Quebec has been close to parity with or greater than, the heavy fuel oil price in that province. In the low case natural gas prices exceed heavy fuel oil prices by about fourteen percent throughout the study period. In the high case, the gas price reaches parity with heavy fuel oil in 1998, and rises more sharply thereafter so that by 2005 the gas price is just over twenty percent higher than heavy fuel oil, as natural gas prices reflect increasing supply costs.

In the western provinces - Manitoba, Saskatchewan, Alberta and British Columbia - the natural gas price is equal to or less than the heavy fuel oil price in the low case, while in the high case the gas price rises to reach and then marginally exceed the heavy fuel oil price by 2005.

These differences in individual fuel price paths, between the two cases - especially that of natural gas, lead to a marked difference between the two cases in the growth of the industrial weighted energy price (see Table 4-6).

In general, electricity remains the most expensive fuel throughout the projection period, followed by oil and natural gas.

4.1.2 Residential Sector

The residential sector energy demand consists of all household energy use (including that in all apartments) and diesel fuel used in agriculture. The major end uses for energy in this sector are space heating, water heating, lighting and appliances. The amount of energy consumed to meet household

requirements is determined largely by variations in the number of households, energy prices and household income.

The relationship between growth in households, income, energy prices and residential energy demand is depicted in Table 4-2 for the period 1973 to 1986, and for both cases over the 1986 to 2005 projection period.

From 1973 to 1986, consumers faced a combination of slowly growing incomes and escalating energy prices. Real energy prices grew at an average rate of almost 4 percent per year. The number of households grew at an average annual rate four times greater than that of residential energy demand, and energy use per household declined at an average annual rate of 2 percent. Underlying these aggregate trends, a number of important structural changes occurred which lead us to believe that the aggregate price-income-energy demand relationship will be different over the next twenty years compared with the period since the first oil price shock.

Since 1973, higher energy prices have induced households, manufacturers and governments to seek and implement energy saving measures:

- building codes were revised with energy costs in mind;
- appliance manufacturers produced more energy efficient equipment;
- home insulation was increased (over 2.2 million houses obtained grants under the Canadian Home Insulation Program);
- consumers switched from older, less efficient oil heating systems (1.2 million houses received federal government grants to switch away from oil) to newer more efficient systems using other fuels, mainly natural gas and electricity; and
- thermostats were set lower.

At the same time, higher incomes led to an increased number of electrical appliances in the home and to larger dwelling sizes, which exerted an upward impact on residential energy demand.

As a result of these changes:

- new homes are now 30 to 40 percent more energy efficient than the average stock of homes;
- new furnaces are 10 to 40 percent more efficient than the average stock of furnaces;
- new water heaters use about 8 percent less energy than the current stock;
- most household appliances are more efficient than those of 10 years ago; and
- only 1.9 million households heated their homes with oil in 1986, down from 3.5 million in 1973.

Even if there were no further change in the energy efficiencies of buildings, furnaces, water heaters and appliances, we would expect a continuing decline in average energy use per house-

Table 4-2

Residential Energy Demand

Average Annual Growth Rates (Percent)

	1973-1986	1986-1990 Case Low	1986-1990 Case High	1990-2005 Case Low	1990-2005 Case High
Households	2.9	1.7	1.7	1.2	1.2
Real Disposable Income per Household	0.4	0.4	1.0	0.4	1.0
Real Energy Price[a]	3.8	-0.6	-0.3	1.1	1.2
End Use Demand[b]	0.7	0.4	0.4	0.8	0.6
Energy Demand per Household	-2.1	-1.3	-1.3	-0.4	-0.6

Levels

	1973	1986	1990 Case Low	1990 Case High	2005 Case Low	2005 Case High
End Use Demand[b] (Petajoules)	1280	1393	1418	1415	1588	1548
Demand per Household (Gigajoules)	203	153	146	145	137	133

Notes: The numbers on this table have been rounded.
[a] The energy price is an index of efficiency adjusted fuel prices for the sector.
[b] Adjusted for variations in weather.

hold as the existing stock is replaced with more efficient units.

The demographic and economic assumptions underlying the energy demand projections for the residential sector in our two cases are:

- The number of households grows moderately in both cases; 1.7 percent per annum from 1986 to 1990 and 1.2 percent per annum from 1990 to 2005.
- Real personal disposable income grows modestly in both cases, 0.4 percent annually in the low case and 1 percent annually in the high case.
- Up to 1990, the real price of energy declines at 0.6 percent per year in the low case and 0.3 percent per year in the high case. Modest growth in energy prices at slightly over 1 percent is projected thereafter for both cases.

Our energy demand projections are generally consistent with the following structural factors.

- There will be virtually no change in output energy requirements for heating the current stock of housing in both cases. This is because for the high case, increases in energy demand resulting from income growth are expected to be roughly offset by declines in demand in response to higher energy prices.

  In the low case, we do not expect homeowners to use energy more liberally in the earlier years when some energy prices remain low, than in the recent past. Past actions to reduce energy use for space heating are, for the most part, irreversible in the short term.

Off oil conversions will continue although at a slower rate than experienced in the early 1980s. They will occur mainly at the normal time of furnace replacement. We anticipate a fairly rapid replacement rate since a large proportion of oil furnaces are over fifteen years old. By 2005, we expect there to be less than one million households heated by oil.

The thermal efficiencies of new housing will continue to improve over the outlook period, with energy use per new household decreasing by about 10 percent in the high case, and 5 percent in the low case by the year 2005, as builders incorporate more energy saving features in new home design. The installation of new, improved windows with triple or quadruple glazing, argon gas between glazing, and insulated plastic frames - which are twice as resistant to heat loss as conventional double glazed units - is among the expected home improvement designs common to both cases. In the low case, builders will have less incentive to include as many features because of the lower value of the resulting energy savings and the desire to constrain housing costs.

We do not anticipate sufficient interest in energy efficiency in either scenario to bring about a surge in the demand for R-2000 homes. This is so because these homes require additional investment with a payback period exceeding the time that most homeowners live in the same home. Furthermore, it appears that not many home buyers value the advantages of living in an R-2000 house compared to one built to conventional standards, which now incorporate many efficiency advances. Therefore, homes with R-2000 features have not increased their market value enough to compensate for the extra costs.

- We expect some improvement in the average efficiency of furnaces in both cases, to a larger extent in the high case. Over the study period, the average fuel efficiency of the stock of furnaces is assumed to increase about 7 percent for the high case and 5 percent for the low case, while for new equipment, we expect improvements of about 5 and 1 percent for the high and low cases respectively. These improvements arise from an increasing share of mid (75 percent) and high (90 percent) efficiency gas furnaces. In 1986, mid and high efficiency furnaces represented 10 and 25 percent of gas furnaces sold respectively. We believe that there is some scope for cost reductions of the high efficiency models as more of them appear on the market, and this will make them even more attractive in later years. Because of lower incomes in the low case and less potential for fuel savings, the high-efficiency gas furnace will be less popular than in the high case. While in the high case, we allow for highly efficient furnaces to represent 100 percent of sales of gas furnaces by the year 2000, they will likely account for only 50 percent of sales in the low case.
- With respect to water heating energy needs, we expect increased use of hot water in the home as more households acquire dishwashers and clothes washing machines. In 1987 only 35 percent of households owned dishwashers.

This increase is mitigated somewhat by expected reduced hot water requirements of the new models of dishwashers and electric clothes washers and by improvements in the fuel efficiency of water heaters. Average energy used for water heating is projected to increase 4 and 3 percent respectively for the high and low cases over the outlook period.

- From 1978 to 1983, the energy efficiency of several types of new appliances sold in Canada showed substantial gains – 43 percent for freezers, 27 percent for dishwashers and clothes washers, and 17 percent for refrigerators. This trend is expected to continue as legislation requiring minimum standards of energy efficiency goes into effect in the U.S. and Canada. Currently, the U.S. requires manufacturers of 13 types of electrical household appliances to improve the efficiency of their products an average of 15 to 30 percent by the early 1990s. Some of the effect of the U.S. legislation will spill over into Canada through competition from imported appliances. Canada imports about 20 percent of its refrigerators and clothes washers from the U.S.

  In Canada, the Government of Ontario plans to encourage appliance efficiency. It recently passed a bill which sets out labelling requirements for appliances and prohibits the sale of appliances which do not meet prescribed energy efficiency standards as set out in the regulations of the Energy Efficiency Act. At the time of writing, these standards had not yet been specified.

  The technology is available to improve appliance efficiencies in Canada, sometimes at little additional manufacturing cost. In the past, energy efficiency improvements in the U.S. have been far greater than those in Canada. For example, the least efficient refrigerator sold in the U.S. is now more efficient than more than half of the models sold in Canada. Until recently, the efficiency of 16.5 cu.ft. refrigerators manufactured in Canada ranged from 100 kW.h/month to 165 kW.h/month, but a comparable model requiring as little as 84 kW.h/month came on the market in 1987.

  We expect sales of appliances to be strong over the outlook period, as aging appliances are replaced (as many as 40 percent of some types of appliances are over 10 years old). During the period 1986 to 2005, we expect average stock efficiency improvements of 18 percent for freezers, 20 percent for refrigerators, 10 percent for washing machines and 15 percent for dishwashers. These estimates are modest and fall short of the mandatory standards in the U.S.

  On the whole, energy required for the operation of appliances is expected to decline by about 6 percent over the study period. The factor contributing most to this decline is the expected improvement in appliance stock efficiency, the effect of which exceeds the increase in energy use resulting from additional purchases of new products. Most new products, such as microwave ovens, video cassette recorders and electronic security systems require small amounts of energy compared with traditional home appliances.

The above considerations for each end use market suggest the following trends in residential energy demand. Residential energy demand is expected to increase by 11 and 14 percent for the high and low cases respectively over the outlook period. We project a steady annual decline in energy demand per household averaging 1.3 percent from 1986 to 1990 in both cases, and 0.4 percent in the low case and 0.6 percent in the high case from 1990 to 2005. This marked slowdown from the more than two percent decline in energy demand per household which prevailed in the period 1973 to 1986 is based on the expectation that net financial gain from conservation projects will be greatly reduced over the outlook period. None the less, in spite of low energy prices, a fall in average energy use in the home will continue.

About 50 percent of the expected improvement in energy intensity of the residential sector comes from the turnover of the housing stock, 20 percent from efficiency improvements in existing furnaces, 10 percent from improved appliance efficiency and another 10 percent from switching to more efficient fuels. More efficient furnaces in new housing, improved new building efficiency, and better water heaters account for the remaining 10 percent.

We project a faster rate of decline in energy use per household in the high than in the low case. This difference is based on the view that higher income growth in the high case enables households to replace appliances at a faster rate and to invest in more energy saving features in new housing. This positive effect of higher incomes on energy efficiency is in contrast to the experience of the 1960s and 1970s. During that period, appliance manufacturers showed little interest in improving the fuel

efficiency of their products and the penetration rates for major household appliances were low. Today, the demand from existing households for these energy intensive appliances is at or close to saturation levels, and we expect mandatory efficiency improvements to new appliances over the study period.

Our projections indicate that by 2005 total residential energy demand in the high case would be only about three percent less than in the low case. This small difference between the two cases results chiefly from our assumptions that:

(i) improvements in the energy efficiency of appliances will be insensitive to energy price movements,

(ii) households have far less scope to respond to high energy prices than they did in the 1970s, and

(iii) the impact of the higher price of energy is offset by the effect of higher income growth.

4.1.3 Commercial Sector

The commercial sector energy demand includes the requirements of the institutional sector and all service industries except transportation and energy utilities.

In general, the energy requirements of these consumers are similar in nature to those of the residential sector. In both sectors, energy is used for heating and cooling buildings, heating water, lighting and the operation of motors and various equipment. However, for commercial consumers as a whole the relative importance of each use differs from that of the residential sector.

The commercial sector is made up of many types of buildings that vary widely in terms of purpose and the amount of time that they are occupied daily. These include office buildings; educational, health care and religious institutions; hotel and recreational facilities; retail businesses and warehouses. The individual character of each type of building gives rise to specific energy requirements that are very different in terms of quantity and nature.

Because of this heterogeneity, it is difficult to accurately assess the impact of a change in the structure of the sector on energy demand. Further, such an assessment would be questionable, given the lack of reliable regional data at the required level of disaggregation.

A summary of the evolution of real energy prices, economic activity and energy demand in the commercial sector for the 1973 to 1986 period and for our two outlooks appears in Table 4-3.

From 1973 to 1986, real energy prices rose at a rate of nearly 4 percent per year. As in the residential sector, commercial sector consumers responded to this price increase by adopting various conservation measures ranging from reduced levels of lighting to the conversion of conventional oil heating systems to more efficient systems using natural gas or electricity. Governments and some energy utilities set up incentive programs to encourage consumers to limit their energy consumption. Building standards were also modified in order to save energy.

During the same period, economic growth boosted energy demand as the number of commercial buildings increased to meet the needs of a growing population. This upward pressure on energy

Table 4-3

Commercial Energy Demand

	Average Annual Growth Rates (Percent)				
	1973-1986	1986-1990 Case		1990-2005 Case	
		Low	High	Low	High
Commercial RDP	3.4	2.5	2.8	1.8	2.4
Real Energy Price[a]	3.7	-0.5	-0.6	0.9	1.1
End Use Demand	1.2	1.2	1.5	1.1	1.3
Intensity	-2.1	-1.3	-1.3	-0.7	-1.1

	Levels					
	1973	1986	1990 Case		2005 Case	
			Low	High	Low	High
End Use Demand (Petajoules)	712	833	873	883	1031	1068
Intensity (Megajoules per $C 1971)	15.1	11.4	10.8	10.8	9.7	9.2

Notes: The numbers on this table have been rounded.
[a] The energy price is an index of efficiency adjusted fuel prices for the sector.

requirements was, however, partially offset by the tightening of energy standards in the construction of new buildings and by conservation efforts in existing buildings. In spite of an increase in economic activity of about 3.5 percent annually, the energy requirements of the commercial sector increased by only 1.2 percent, resulting in a 25 percent decrease in energy intensity over the study period.

Over the last ten years, the energy consumption habits of commercial consumers have changed significantly. For example, the use of advanced technology has resulted in new buildings that use less than 1.0 gigajoule of energy per square metre annually. Hydro Place in Toronto, which has a heat recovery and storage system, consumes as little as 0.6 gigajoules of energy per square metre each year. The courthouse in Newmarket, Ontario, which was built in the early 1980s, is another example of energy efficiency, with an annual consumption of only 0.5 gigajoules per square metre. During the 1970s, buildings of the same type could use up to 3.0 gigajoules per square metre annually.

During the projection period, we expect that energy demand in the commercial sector will be influenced by:

- A considerably less rapid increase in real energy prices than in the past: average annual declines of 0.5 and 0.6 percent from 1986 to 1990 in the low and high cases respectively, and increases of 0.9 and 1.1 percent from 1990 to 2005 in the same two cases;

- Less rapid growth in economic activity than during the period from 1973 to 1986. Compared with that period, the low case clearly stands out with average annual rates of increase of 2.5 percent from 1986 to 1990, and 1.8 percent from 1990 to 2005. In the high case the sector's economic growth averages 2.8 and 2.4 percent annually over the same two periods.

These trends in prices and economic growth, combined with the demand management programs of some electric utilities, will lead to significant structural changes.

Among the structural changes expected over the course of the study period, we project that the following will have the greatest impact;

- Continued conservation by commercial consumers, in spite of the price declines projected to the end of the 1980s and weak economic growth especially in the low case.

- An increase in the amount of space for offices, hotels and businesses as a result of a rise in economic activity; a decline or, at the very most, no change in the amount of space occupied by hospitals which are the most energy intensive commercial buildings (In spite of an aging population and increased demand for health care, it is likely that more home care will be offered and the number of old age homes will increase.); relatively slow growth in the number of educational facilities in view of the changing demographic structure.

- The number of modern buildings incorporating improved energy efficiency features will vary with the level of economic activity. Modern technology in the new buildings is bound to play an important role in the reduction of energy intensity as these buildings replace older, less efficient buildings. Stronger economic growth in the high case will lead to the construction of a greater number of these buildings than in the low case.

  In the area of new construction, it appears that an increasing number of large commercial buildings are equipped with systems to recover and redistribute heat. These systems have become useful where there is intensive use of office equipment which produces a certain amount of heat and yet needs a cooler environment in order to operate properly. The heat produced is recovered and redistributed wherever it is needed.

  Windows designed to absorb infra-red solar rays, heat pumps, better insulation materials, efficient lighting systems and computerized energy management systems are other technological developments expected to play an increasingly important role in improving the energy efficiency of new commercial buildings.

The implementation of electricity demand management programs in Ontario and British Columbia, aimed at limiting growth in the demand for this form of energy, will also have an important effect on electricity and energy demand in the commercial sector.

The objective of the demand management programs of Ontario and British Columbia is to postpone capacity expansion. The programs are aimed at consumers in all sectors. However, the commercial sector appears to be a target with very promising potential for conservation, especially in the area of

energy requirements for lighting and the operation of motors. It is estimated that substantial electricity savings can still be attained by measures such as:

- turning off or eliminating a certain number of lights in areas where a reduced level of lighting can be tolerated;
- installing energy efficient fluorescent tubes, which consume only 32 or 34 watts, to replace conventional ones which use 40 watts;
- installing efficient ballasts which consume up to 12 percent less energy than the conventional type; and
- using motors which supply an output appropriate to the requirements, and motors with variable speeds in ventilation systems.

In the low case, we assumed that the slow growth in Ontario's electricity demand would not justify the implementation of a demand management program for that province. However, the impact on energy demand in British Columbia, where a demand management program has recently been set up is incorporated in the results. The effect of conservation in the commercial sector in British Columbia is estimated at about 5 petajoules in 2005 under such a program.

In the high case, with more rapid growth in electricity demand, we have assumed the implementation of a demand management program in Ontario starting in 1991. In British Columbia the program which is already in place is assumed to continue. The conservation resulting from these programs for these two provinces combined is estimated at about 25 petajoules in 2005.

Apart from these two provinces, we do not anticipate the implementation of other similar incentives for conservation in other parts of the country during the projection period. For other regions the relatively slow growth in real energy prices in the two cases will restrict the growth in conservation and efficiency measures especially in existing buildings.

These expectations lead us to project increases in the energy demand of the commercial sector of 24 percent in the low case and 28 percent in the high case over the course of the study period. This would result in an average annual decline of 1.3 percent in commercial energy demand per unit of production from 1986 to 1990 in both cases, and declines of 0.7 and 1.1 percent from 1990 to 2005, in the low and high cases respectively.

Although energy prices are slightly higher in the high case than in the low, commercial energy demand in the high case exceeds that in the low case. This result agrees with past observations that commercial energy demand has reacted more strongly to variations in economic growth than to price fluctuations. In fact, if the results of the two cases are adjusted in order to remove the impact of electricity demand management programs, the difference between energy demand in the two cases would increase from 37 petajoules in 2005 to 57 petajoules, a difference of some 6 percent. This disparity would have been greater if the assumptions with regard to energy prices and economic growth within each case had not had somewhat offsetting effects on commercial energy demand.

4.1.4 Industrial Sector

The industrial sector includes the manufacturing industries, forestry, construction and mining, but excludes the petrochemical industry (discussed in Section 4.1.5). The sector accounts for approximately 35 percent of total end use energy demand. However, most of the energy it consumes is concentrated in a few small but highly energy intensive industries. Table 4-4 shows energy consumption for major industries in 1986.

Pulp and paper is by far the largest energy user; it consumed over 31 percent of the total industrial energy demand in 1986. In 1986 the combined energy consumption of the mining, pulp and paper, iron and steel, smelting and refining, cement and chemicals industries accounted for 74 percent of industrial energy demand, but the output of these industries accounted for only 25 percent of industrial production.

British Columbia, Alberta, Saskatchewan and the Atlantic provinces have a large share of energy intensive industries - pulp and paper, mining and smelting - which result in higher energy intensities for those provinces than for others (Table 4-5).

Energy savings per unit of output are the result of measures undertaken by the industry in response to a variety of incentives and risks in the market place. These measures fall into two categories:

- Measures that reduce energy use per unit of output without necessarily affecting the productivity of labour and capital, for example waste heat recovery techniques and use of high efficiency electric motors. These types of measures tend to be

Table 4-4

Intensity of Industrial Energy Use, Levels and Distribution of Total Industrial Energy by Selected Industries in 1986

	Intensity[a]	Petajoules	Percent Share[b]
Forestry	18	15	1
Mining	85	300	12
Total Manufacturing	74	2086	86
Pulp and Paper[c]	347	762	31
Iron and Steel	238	270	11
Smelting and Refining	192	170	7
Cement	456	58	3
Petroleum Refining	479	104	4
Chemicals[d]	118	233	10
Other Manufacturing	22	489	20
Construction	5	33	1
Total Industrial	**62**	**2434**	**100**

Notes: The numbers on this table have been rounded.
[a] Megajoules per 1971 dollar of industrial output.
[b] Share of sub-sector energy demand to total industrial energy demand.
[c] Pulp and Paper and allied products.
[d] Excludes feedstocks used in the petrochemical sector.

Table 4-5

Intensity of Industrial Energy Use by Region in 1986

(Megajoules per 1971 dollar of industrial output)

Atlantic	92
Quebec	59
Ontario	44
Manitoba	50
Saskatchewan	70
Alberta	104
British Columbia	102
Canada	62

Note: The numbers on this table have been rounded.

driven by changes in average and relative energy prices and by the length of the payback period of the measures.

- Measures that reduce energy intensity because of a change to a particular industrial process, for example continuous casting in steel-making, greater automation and use of computers. These measures are usually implemented as a result of broader considerations related to output efficiency and the general competitiveness of an industry.

Each of these measures can be identified as having contributed in the past to reductions in energy intensity and the distinction between these two categories provides a useful framework for analysis of future changes. However, not all reductions in measured intensity necessarily result from these two measures.

A third factor which has contributed to reduced energy intensity is the increased share of electricity, as electricity is substituted for other fuels. If a process uses a fuel other than electricity, a conversion loss is incurred between the input of the fuel and the output or production of useful energy. Thus more units of input energy are required than are ultimately available to the process. If the process converts to electricity, as many "output" units of fuel are required as would have been had the process used other fuels. However, there is no efficiency loss between the receipt and use of electricity; as a result fewer "input" units of energy are needed to make available the same amount of useful energy. In this way, measured energy intensity (input units of energy per dollar of output) is reduced when industries substitute electricity for other fuels. This decline in measured intensity need not reflect an efficiency gain in terms of a process, but merely a conversion to electricity from another fuel.

Thus the three measures which may cause a decline in energy intensity are: those resulting from reductions in energy use which reflect the impact of energy prices; those which reflect a change in process, independent of energy prices; and those which result from use of electricity rather than other fuels. Any of these three may be combined, as in the case of thermo-mechanical pulping which is a more efficient process, using less energy than other pulping processes, but which also uses electricity.

Energy prices and economic activity have played an important role in determining industrial demand for energy in the 1973 to 1986 period. Some energy savings were realized during this period although it was composed of two sub-periods characterized by distinct and offsetting trends.

The 1973 to 1982 period saw large energy price increases and relatively low rates of growth of labour productivity and investment. Energy savings of some 0.7 percent per year over this period reflected a concerted effort on the part of industrial consumers to reduce energy use in the face of large price increases, reflecting the first kind of energy savings discussed above.

In contrast to the 1973 to 1982 period, the 1982 to 1986 period saw very modest energy price variations and much larger variations in productivity and investment. Over this period concern over energy efficiency was overshadowed by broader concerns of economic efficiency and competitiveness. Growth in industrial output, increased capacity utilization and productivity and the lagged impact of increasing energy prices in the latter half of the 1970s and early 1980s, led to notable improvements in the efficiency of industrial energy use from 1982 to 1986. Most of these changes resulted from the adoption of new processes, motivated by concerns for competitiveness and productivity, rather than energy costs. During this period energy intensity fell by one percent per year on average and energy intensive industries showed above average improvements in energy savings.

Overall trends in aggregate industrial energy demand and intensity mask structural changes which have occurred in energy intensive industries. Major energy-related developments in these intensive industries are summarized below.

The **mining** industry consists of activity in metal mining industries, non-metal mining industries, energy mining, and quarry and sand pit industries. The distribution of mining energy use and intensity across regions reflects the differing mix of this industry regionally, and the variation in energy use within the mining sector.

Although the mining sector is not one of the most energy intensive industries, it accounts for about 12 percent of industrial energy demand. On a regional basis, Alberta accounts for the largest share of energy use in the mining sector in Canada. This share increased from 26 percent in 1978 to 48 percent in 1986, mainly because of the increasing importance of energy mining requirements (particularly bitumen projects).

From 1978 to 1986, energy intensity in mining increased by 21 percent. This resulted from an increase in bitumen mining, which is very energy intensive. Mining sector energy intensity in all regions except Alberta showed a decline, mainly as a result of better energy management, a greater application of heat recovery methods and the use of more efficient electric motors.

As mentioned earlier the **pulp and paper** industry accounts for the largest single share of industrial energy demand. It is also the only industry where by-products of the production process (wood waste, or hog fuel and pulping liquor), themselves provide the largest proportion of energy requirements.

The share of these fuels has increased in recent years at the expense of purchased fuels such as heavy fuel oil, coal and, to a lesser extent, natural gas. Purchased fuels accounted for 350 petajoules of energy demand in 1978 and 352 petajoules in 1986, an increase of only 2 petajoules, while hog fuel and pulping liquor consumption increased by 83 petajoules, from 326 petajoules in 1978 to 409 petajoules in 1986, 54 percent of this sector's total energy needs.

Improvements in energy use in the pulp and paper industry from 1978 to 1986 were generally the result of high rates of capacity utilization, greater application of heat recovery technologies, increased use of the thermo-mechanical pulping (TMP) process and better energy management. Between 1975 and 1984, total Canadian TMP capacity grew from 620 to 12,275 air-dry tonnes per day. This represented 34 percent of mechanical pulping capacity and 15 percent of the total pulping capacity in Canada in 1984.

Another factor which contributed to improved energy intensity in the pulp and paper industry was the increase in the market share of electricity from 18 percent in 1978 to 24 percent in 1986. This was mainly the result of increased penetration of the TMP process and of the success of Hydro-Québec's surplus program aimed at the industrial sector. This program increased electricity's share over and above that resulting from the adoption of the TMP process. However, the increasing use of internally generated fuels, which are less expensive to the industry but are considerably less efficient than purchased fuels, more than offset the impact of these improvements on measured energy intensity. As a result, total input energy intensity in the pulp and paper industry shows little improvement from 1978 to 1986.

Canadian **steel production** in 1986 was considerably lower than in 1979, when it was at an historical peak. However, energy use per

unit of output declined by 6 percent between 1979 and 1986 despite lower capacity utilization which normally causes energy intensity to rise. Energy savings were the result of better energy management, greater shares of steel produced using the continuous casting production process and in electric furnaces, and increased productivity following large investment in new equipment, greater automation and computerization.

From 1978 to 1986, the share of steel produced using the continuous casting process increased from 20 to 46 percent. This has led to productivity improvements of some 20 percent resulting from the elimination of a discontinuity which characterizes the traditional steel-making process and leads to wasted materials.

The penetration of electric arc furnaces paralleled that of the continuous casting process, the share of steel produced using this process increased from 22 percent in 1978 to 29 percent in 1986. As in the pulp and paper industry, increased use of electricity in steel production led to measured improvements in intensity.

The **smelting and refining** industry consists of the aluminium industry and a large number of plants involved in the smelting and refining of such metals as copper, nickel, lead, zinc, gold and titanium. The aluminium industry is by far the largest energy consumer in this sub-sector. It accounted for an estimated 85 percent of the total smelting and refining energy demand in 1986.

In smelting and refining, energy intensity declined by 12.4 percent over the 1978 to 1986 period. Energy savings were largely the result of: better energy management; greater use of more efficient fuels (the share of electricity increased from 62 percent in 1978 to 72 percent in 1986); relatively high capacity utilization, particularly in the aluminium industry; and a greater application of newer and more energy efficient technologies and processes such as automation and computerization.

Cement production is based on two processes referred to as the wet process and the dry process. The dry process uses about twenty percent less energy per unit of output than the traditional wet process. Currently about 80 percent of cement production is based on the dry process, a substantial increase over 1978 when 65 percent of the cement was produced in this way. However, use of these processes varies across regions. In 1986, in the Atlantic region and Saskatchewan, all cement was produced using the more efficient dry process. In Manitoba, on the other hand, all cement was produced using the wet process. In other regions the use of the dry process dominated, accounting for 65 to 80 percent of cement production in these regions.

Although the cement industry pursued its shift towards the dry process throughout the 1979 to 1986 period, published data shows an increase in energy intensity of some 19 percent over this period. Capacity utilization in the cement industry fell from 83 percent in 1979 to 61 percent in 1986, contributing to the increase in intensity. The Canadian Industry Program for Energy Conservation has estimated that over this period, energy savings in the cement industry, adjusting for low capacity utilization and other non-efficiency factors, were in the range of 20 percent.

In recent years, the cement industry has moved towards the use of refuse-derived fuels such as old tires in Ontario and biogas in B.C. In Quebec it is expected that used oils and solvents will begin fuelling some cement production in 1988. In general, these fuels are less energy efficient and their use will tend to increase energy intensity.

The industrial sector's demand for energy in the projection period will be determined largely by the growth in industrial output, energy prices, shifts in output among industries within the industrial sector and trends in productivity and investment. Utility-sponsored demand management programs such as those proposed by Ontario Hydro and B.C. Hydro will also have some influence.

The share of energy-intensive industries in the industrial sector can have a major impact on energy use and energy intensity of the sector as a whole. In our projections, the share of these industries declines moderately throughout the projection period in both cases - from 25.5 percent in 1986 to between 23 and 24 percent in 2005. We estimate that if the energy intensive industries were to maintain their 1986 share of output to the year 2005, industrial energy demand would be four to five percent higher than we have projected for the high and low cases.

While we expect price and output to continue to influence energy demand in the future as they have in the past, in a number of cases technological changes and concerns about total productivity not specifically driven by energy prices

may be more important determinants of industrial energy demand and intensity.

In the low and high cases industrial output is projected to grow steadily at average annual rates of 2.5 and 3.5 percent respectively over the projection period.

A number of uncertainties surround the industrial energy demand projection. Among the most important are:

- the rate of adoption of new production processes which affect energy demand, e.g. the dry process displacing the wet process in cement manufacturing;

- the rate of adoption of energy-saving techniques, e.g. waste heat recovery methods;

- the shift of output between energy intensive and less energy intensive industries;

- the impact of major technological developments, such as the increased use of energy efficient electrical motors and the development and application of superconductivity;

- trends in productivity and the rate of investment; and

- environmental issues.

The results of our industrial energy demand projections should be viewed with these uncertainties in mind.

The projections of industrial energy use presented in this report generally reflect the following industry specific developments in both cases:

- In the **mining** industry, we project a 2 percent total improvement in efficiency by 2005 in all regions but Alberta. In Alberta, efficiency improvements are masked by the rising requirements of energy mining projects, particularly bitumen.[1] Energy requirements for bitumen projects increase from about 72 petajoules of natural gas in 1986 to 146 petajoules of natural gas in 2005 in the low case, and to 161 petajoules each of coal and natural gas in the high case.

- In the **pulp and paper** industry we expect:

  i) continued penetration of TMP leading to total energy efficiency improvements of about 3 percent over the projection period; plus

  ii) additional improvements in energy efficiency of 5 percent by 2005 resulting from better energy management, use of heat recovery methods, use of efficient electric motors and more general total productivity considerations; and

  iii) a shift towards newsprint production from 20 percent of the industry's output currently to 25 percent by 2005. Newsprint production requires 40 percent less energy than kraft pulp production as newsprint relies less on wood wastes.

- We expect energy efficiency improvements in **iron and steel** production of about 8 percent by 2005. This will result largely from the increased use of mini-mills and electric arc furnaces and the continued penetration of the continuous casting process.

- For the **aluminium** industry, we expect that the current most efficient technologies will be adopted by all plants. In both cases we expect that this will lead to declines in energy intensity of about 8.5 percent in Quebec and 11.3 percent in British Columbia by 2005.

- **Smelting and refining** other than aluminium is projected to show about 5 percent improvement in energy efficiency by 2005 resulting from the introduction of technological improvements embodied in new capital.

- In the **cement** industry, we have assumed that all cement will be produced using the dry process by 2005. We also expect that overall efficiency considerations in this industry will lead to a decline in energy intensity of some 3 percent over the projection period.

These industry-specific observations apply to both the high and low cases. A number of trends in industrial energy use distinguish the two cases and are in addition to the industry specific observations:

- In the **high case for all industries,** we project an additional 5 percent improvement in energy efficiency by 2005 resulting from better energy management, the application of heat recovery techniques and the use of high efficiency motors. Approximately 35 percent of Canadian electricity demand is used to

1. See Chapter 7 for detailed assumptions on bitumen projects.

drive electric motors in the industrial sector. We expect greater penetration of currently-available high efficiency motors, particularly in the pulp and paper, mining and chemicals industries. As a result the average efficiency of electric motors in the one to 200 horsepower range should increase, in the high case, by about 5 percentage points from its current level of 89 percent. We believe that the economic and pricing environment defined for the high case would make these measures viable.

- In Ontario and British Columbia the implementation of **electricity demand management programs** will also have some influence on industrial energy demand and intensity. We expect that these programs will result in reductions in industrial demand of 15 petajoules in the high case and 3 petajoules in the low case in 2005, below what they would otherwise have been.

In sum, these developments imply average annual increases in total industrial energy demand of 1.7 percent in the low case and 2.8 percent in the high case over the projection period. Energy intensity is projected to decline by about 0.7 percent per year in both cases from 1986 to 2005.

From 1986 to 1990, we expect energy intensity to decline in both cases despite present low energy prices (see Table 4-6). This trend reflects the view that the rapid application of energy conservation measures and technologies that was triggered by the energy price shocks of the late 1970s and early 1980s will continue over the next few years. By the end of the 1980s most of the relatively easy-to-apply

Table 4-6

Industrial Energy Demand

Average Annual Growth Rates (Percent)

	1973-1986	1986-1990 Case		1990-2005 Case	
		Low	High	Low	High
Industrial RDP	1.3	1.9	3.5	2.6	3.5
Real Energy Price[a]	5.6	-1.3	0.1	1.8	3.0
End Use Demand	n/a	1.3	3.3	1.8	2.7
Intensity	n/a	-0.6	-0.2	-0.8	-0.8

Levels

	1973	1986	1990 Case		2005 Case	
			Low	High	Low	High
End Use Demand (Petajoules)	n/a	2434	2561	2777	3366	4134
Intensity (Megajoules per $C 1971)	n/a	61.9	60.4	61.5	53.8	54.5

Notes: The numbers on this table have been rounded.
[a] The energy price is an index of efficiency adjusted fuel prices for the sector.
n/a: Not available due to discontinuities in data.

and less expensive energy saving measures and technologies are likely to be in place.

Between 1986 and 1990 intensity improvements are less in the high case than in the low. This reflects increased requirements for bitumen in the high case by 1990 and a slightly higher share of output of energy intensive industries in that case.

We expect the decline in energy intensity to continue throughout the 1990 to 2005 period in both cases. Over the longer term, savings in energy use per unit of output will come largely from the replacement of existing equipment by more efficient capital stock, technological changes over a broad front, and, to a lesser extent, from a shift in output towards less energy intensive industries, and a shift to more energy efficient fuels, in particular electricity. Despite higher growth in energy prices, investment and labour productivity, the rate of decline in the high case is similar to that in the low case.

As seen in Table 4-6, energy intensity is slightly higher in 2005 in the high case than in the low. This appears to contradict our assumptions, but is explained largely by the increased requirements of energy for bitumen projects in the high case, relative to the low. If we were to exclude the mining sector, energy use per unit of output would be slightly lower in the high case than in the low case. A less important reason is that the share of energy intensive industry output is marginally higher in the high case than the low case throughout the projection period, reflecting the importance of traded goods and primary products to the high case.

By 2005 industrial energy demand in the high case is 767 petajoules

or 23 percent higher than in the low case. This happens because industrial output is 21 percent higher in the high case and there is almost 180 petajoules more energy use for bitumen production in the high case than in the low.

4.1.5 Non-Energy Hydrocarbon Use

In 1986, 598 petajoules (8.5 percent) of end use energy demand was used for non-energy purposes. Of this total, 375 petajoules (63 percent) related to petrochemical requirements, 123 petajoules (20 percent) to asphalt, and the remainder to lubricants, greases, petroleum coke and other non-energy petroleum products. Historical and projection period data are presented in Table 4-7.

We include in petrochemical hydrocarbon requirements natural gas used as feedstock[1], and light oil fractions (such as naphtha) and natural gas liquids (propane, butanes and ethane) used for both feedstock and fuel[2], to produce ammonia and primary petrochemicals:

(i) ammonia from natural gas;

(ii) methanol from natural gas;

(iii) olefins (ethylene, propylene, butadiene and butylene) from light oil fractions or natural gas liquids;

(iv) aromatics (benzene, toluene and xylene) from light oil fractions; and

(v) other products[3].

Because these primary products are used to produce a very wide variety of industrial and consumer goods, including plastic products, adhesives, solvents, cosmetics, synthetic fibres, sizing, foam products, coolants, synthetic rubber products, and fertilizers, the demand for hydrocarbons for use in petrochemical production depends ultimately on the quantities consumed of each of these final products. Furthermore, the demand in Canada for hydrocarbons for petrochemical production depends on our trade in primary and intermediate petrochemicals as well as in final products.

Therefore projections of petrochemical feedstock demand depend on several uncertain factors:

- Canada's competitive position in world petrochemical markets, which is affected by relative feedstock costs, capital and operating costs, transportation costs and access to markets;
- the timing of construction of new Canadian plants during the projection period, which is affected by the world-wide scheduling of plant capacity, and by the growth in product demand; and
- product slate requirements and, for those plants with feedstock flexibility, prices of alternative feedstocks.

The relatively long (four to five year) time period required for the planning and construction of new plants, combined with the variability of both feedstock prices and product demand, has resulted in cycles of strong demand and high capacity utilization alternating with

Table 4-7

Non - Energy Uses

(Petajoules)

	1986	1990 Case Low	1990 Case High	2005 Case Low	2005 Case High
Petrochemicals					
Natural Gas	149	166	166	181	181
Oil	127	169	169	219	219
NGL	99	123	123	174	174
Total Petrochemicals	375	457	457	574	574
Asphalt	123	128	135	165	186
Other Non - Energy Uses	100	129	125	176	168
Total Non-Energy	**598**	**714**	**717**	**915**	**928**

Note: The numbers on this table have been rounded.

1. In the October 1986 Report, natural gas used as fuel in petrochemical production was also included. In the current report it has been included instead in industrial gas demand. This change brings our treatment of natural gas into line with that followed by Statistics Canada.
2. For light oil fractions and NGL, our classification is the same as that followed by Statistics Canada.
3. These include carbon black produced from light oil fractions or natural gas, and products of refineries such as heptene and octene.

periods of depressed product market conditions and large capacity surpluses during which producers have not always recovered their operating costs. This is a global problem, affecting the industry in Canada and in other countries. To operate efficiently and minimize production costs per unit of product, plants must run at essentially full capacity, so that in this industry it is generally preferable to shut down rather than to run at low capacity utilization, producing high cost, uncompetitive output.

Most of Canada's capacity is relatively new, world-scale and technically efficient. Modification and modernization of units takes place on an ongoing basis.

Four new ammonia plants with a total annual capacity of about 800 kilotonnes opened in British Columbia and Alberta in 1986 and 1987, while two smaller ammonia plants in Alberta (with a total capacity of about 160 kilotonnes per year) were shut down in 1987.

Weak markets in 1986 and 1987 led to the closing of methanol plants for short periods during both years.

In Quebec, a small ethylene plant (55 kilotonnes per year) was closed at the end of 1986 but a larger plant (200 kilotonnes per year capacity) was modernized between 1986 and early 1988 to permit a much greater degree of feedstock flexibility. Up to 75 percent of feedstock can now be propane and butanes, the remainder being naphtha and gas oil.

A Quebec refinery which had been closed early in 1986 was partially reactivated at the end of that year and is now producing aromatics and some other petrochemicals.

In 1987, the petrochemical industry overall returned to profitability after several years of losses. The volume of production increased by 23 percent in 1987 over 1986, and capacity utilization increased for the sixth consecutive year, reaching 95 percent, its highest level in many years. Exports rose 47 percent to $2.6 billion and exceeded imports by $557 million.

The strong performance of the industry in 1987 resulted from favourable world economic growth, the lower value of the Canadian dollar, and the lower cost of feedstocks as a result of reductions in both world oil prices and Canadian natural gas prices, the latter following upon the introduction of market-sensitive pricing. However, some products performed better than others. Production of methanol, ethylene, butadiene, butylene, and benzene were all up by 10 to 16 percent, but production of propylene and toluene were unchanged, and xylene and ammonia production fell slightly. Prices generally increased, but prices of butylene, toluene, xylene, ammonia and carbon black fell.

In view of the current strong demand, many North American petrochemical companies are considering expanding, but given the past history of cyclical over-expansions, many are choosing to pursue the less risky strategy of enlarging existing plants rather than building new ones.

We expect that generally over the longer term both world and Canadian demand for petrochemicals will increase at about the same rate as overall economic growth, although new products and changing consumer tastes could lead to a higher rate of increase.

The terms of the Canada/U.S. Free Trade Agreement provide for the tariffs on primary petrochemicals to be reduced to zero progressively over a five year period; ammonia is already duty-free. Further, they provide for the tariffs on some derivative products to be eliminated over five years and on others over ten years. The tariff reductions will facilitate access by Canadian and American producers to each other's markets, increasing competitive pressure. Relative feedstock prices and plant efficiencies will become even more critical determining factors of trade and domestic production. The capacity addition assumptions underlying our projections, described below, are based in part on the Free Trade Agreement coming into effect.

Given the uncertainties in petrochemical demand and prices, and in the competitiveness of the Canadian industry, we decided to use the same assumptions in both our low and high cases. These assumptions were based on our consultations.

Petrochemical feedstock requirements for natural gas for the production of ammonia and methanol are projected to reach 181 petajoules by 2005 from 149 petajoules in 1986, an average annual increase of about one percent:[1]

- One ammonia plant in Alberta which is currently shut-down will restart operations in 1990 and two new ammonia plants, each with a capacity of 350 kilotonnes per year, will be built in Alberta -

1. These numbers are much lower than those in the October 1986 Report because of the exclusion of fuel and the smaller number of new ammonia plants assumed.

one coming on-stream in 1995 and one in 2000.[1]

- No new methanol capacity will be added during the projection period, although recently world-wide capacity and demand have come closer together and it has been reported that Ocelot is considering expansion of its British Columbia facility. Increased use of methanol as a fuel or blending agent, or its use in the production of methyl tertiary butyl ether (MTBE), which is used to increase the octane level in gasoline, could justify new capacity before 2005. Although there have been discussions concerning the construction of MTBE facilities in Alberta and Quebec, no firm announcements had been made at the time of writing.

We project that ethane use for feedstock and fuel will increase from 84 petajoules in 1986 to 140 petajoules by 2005, an annual growth rate of almost 3 percent:[2]

- A new ethylene plant with a capacity of 680 kilotonnes will come on-stream in Alberta in 1995, and an increase of 10 percent in the capacity of the existing ethylene plants in Alberta will occur by 1989. We recognize that ethylene capacity decisions could be affected by any changes to Alberta government ethane policy.

- There will be an increase of 2 percent per year from 1988 to 2005 in the capacities of the ethylene and aromatics plants in Ontario and Quebec from debottlenecking and progressive capacity increases. We have used the same rate of increase in both cases, although it is possible that a higher rate could occur in the high case.

Use of oil for petrochemical feedstock and fuel, which was 127 petajoules in 1986, is expected to increase, to 219 petajoules by 2005.[3] The industry in eastern Canada uses mainly oil; however, it has been increasing its feedstock flexibility. The choice of feedstocks at any time depends on both relative feedstock prices and the desired product slate. As there is a large range of potential feedstock combinations and each produces a different slate of products, without specific projections of the prices of each type of alternative feedstock and the volumes and prices of each product produced by various feedstock slates, it is impossible to project a feedstock slate with any confidence.

We are assuming, based on recent views and experience, only a modest increase in the quantities of LPG substituted for oil. This, combined with the increase in overall feedstock requirements from the industry's recovery in 1987 and the assumed 2 percent per year increase in the capacities of the ethylene and aromatics plants in Ontario and Quebec from 1988 to 2005 discussed above, results in the projected increase in oil use.

Propane use for feedstock and fuel which was 8 petajoules in 1986 increases to 28 petajoules in 2005. Butanes accounted for 7 petajoules in 1986, but their use appears to have decreased in 1987 as oil prices fell. Butanes use is expected to be in a range of 5 to 7 petajoules over the study period.[3]

Asphalt is the most important non-energy hydrocarbon use other than petrochemical industry requirements. Asphalt is used primarily for surface pavement of roads and airport runways. It is also used for roofing; lining canals, reservoirs, dams and dikes; binding rocks in breakwaters; insulating underground waterpipes and communication cables; and railroad beddings. Trends in the extent of road paving will have a major influence on total asphalt demand, as paving accounts for some 75 percent of total asphalt use.

Over the projection period, asphalt demand will continue to be influenced by the application of recycling technology. We project demand for asphalt to grow at average annual rates of 1.6 percent and 2.2 percent in the low and high cases respectively. This reflects the view that changes in demand for this product are largely determined by variations in economic activity.

Lubricating oils and greases, petroleum coke, naphtha specialities and other non-energy petroleum products account for 17 percent of non-energy demand. We project the demand for these products taken together to grow at average annual rates of about 3 percent in

---

1. This is a reduction from the projections in the October 1986 Report which included five new plants in the period 1990 to 2005.
2. Our current projections for ethane feedstock and fuel are higher than those in the October 1986 Report because of our current assumptions regarding progressive annual capacity increases in existing plants in Eastern Canada.
3. In these projections we are assuming less substitution of LPG for naphtha than in the October 1986 Report which assumed that the maximum substitution consistent with plant configurations would occur. This, along with our assumption of progressive annual capacity increases, results in projections for LPG which are lower, and for oil which are higher, than those contained in the October 1986 Report. We expect the quantities of LPG used for petrochemical feedstock and fuel to be small relative to oil, and to be very sensitive to relative feedstock prices.

both cases from 1986 to 2005. By 2005 these products would then account for slightly less than 20 percent of non-energy demand.

4.1.6 Transportation Sector

The transportation sector includes road, rail, air and marine transport. The road sector is, by far, the largest, accounting for 82 percent of total transportation energy use in 1986. Air sector energy use accounts for nine percent of total transportation sector demand, with the rail and marine sectors sharing the remainder equally.

Petroleum products account for 99 percent of energy demand in the transportation sector. In fact, the sector's demand for oil currently constitutes 62 percent of total oil end use. Motor gasoline dominates fuel use in transportation (65 percent), followed by diesel (22 percent) and aviation turbo (9 percent), with the remainder (4 percent) accounted for by heavy fuel oil, propane, aviation gasoline, natural gas for vehicles (NGV) and electricity.

With the *road sector* accounting for such a large share of total transportation energy use, variations in transportation energy demand mainly reflect developments in road transport. Motor gasoline accounts for almost the entire fuel use by automobiles, while energy used to move trucks is more evenly divided between gasoline (57 percent) and diesel (40 percent). Light trucks account for about 75 percent of gasoline use by trucks while extra-heavy diesels account for 91 percent of diesel road use.

Growth in road transportation energy demand is approximately equal to the sum of the growth rates of the stock of vehicles, the average fuel efficiency of the stock and the average distance per vehicle (Tables 4-8 and 4-9).

Growth in car and truck stock is determined by real personal disposable income (cars) or real domestic product (trucks), operating costs and financing charges. Average fuel efficiency of the vehicle stock depends upon the rate of improvement in fuel efficiencies of new vehicles in various weight classes, shifts between weight classes and the rate of turnover of the vehicle stock. For example, the average fuel efficiency of the stock of gasoline trucks depends not only upon improvements in efficiencies of new light and medium/heavy trucks, but also upon changes in the weight mix of new models. The weight mix of trucks is, in turn, influenced by relative growth in demand for recreation vis-à-vis freight transport, buyer preferences, and the relative prices of labour, fuel and equipment in truck transport. A rise in the price of fuel and wages could, for example, lead to changes in truck configurations to improve payload efficiency and reduce growth in fuel use. Similar considerations apply to changes in the average distance per vehicle. Average distance depends not only upon income and fuel prices but also upon the average age of the vehicle stock and the number of vehicles owned.

The historical evolution of energy use in the transportation sector can be divided into three phases: the period from 1965 to 1973, which

Table 4-8

Determinants of Motor Gasoline Use

Average Annual Growth Rates (Percent)

	1973-80	1980-86	1986-1990 Case		1990-2005 Case	
			Low	High	Low	High
Car Sector						
Real Gasoline Price	2.5	1.8	-0.5	2.5	0.2	0.5
New Car Sales	-0.6	2.7	0.6	0.8	1.6	2.0
Car Stock	3.8	1.6	1.8	1.8	1.8	2.0
New Car Fuel Efficiency (L/100 Km)	-4.0	-4.3	-0.4	-0.5	-0.6	-0.8
All Car Fuel Efficiency (L/100 Km)	-0.7	-4.4	-3.3	-3.4	-0.9	-1.0
Average Distance per Car	-0.6	1.0	0.9	0.9	0.0	0.0
Car Gasoline Demand	2.4	-2.1	-0.7	-0.7	0.9	0.9
Truck Sector (Gasoline)						
New Truck Sales	3.6	4.0	4.3	5.4	1.2	1.5
Truck Stock	6.8	1.3	4.7	4.9	2.1	2.7
New Truck Fuel Efficiency	-1.0	-4.3	-0.9	-1.0	-0.7	-0.8
All Truck Fuel Efficiency	-1.3	-3.2	-3.7	-3.8	-1.1	-1.3
Average Distance per Truck	-2.0	-1.2	0.2	0.2	-0.3	-0.4
Truck Gasoline Demand	3.3	-3.6	0.9	0.9	0.6	0.7

Note: The numbers on this table have been rounded.

Table 4-9

Determinants of Road Diesel Use

Average Annual Growth Rates (Percent)

	1973-80	1980-86	1986-1990 Case Low	1986-1990 Case High	1990-2005 Case Low	1990-2005 Case High
Truck Sector (Diesel)						
RDP in Goods Producing Industries	1.6	1.1	1.7	3.3	2.6	3.5
Real Truck Diesel Price	1.3	4.5	-2.4	1.3	0.6	1.0
New Truck Sales	6.7	4.8	1.9	3.1	2.3	3.6
Truck Stock	10.4	4.3	8.0	8.0	3.6	4.7
New Truck Fuel Efficiency (L/100Km)	-2.5	-1.2	-0.7	-0.7	-0.5	-0.6
All Truck Fuel Efficiency (L/100Km)	-0.9	-1.8	-2.0	-2.1	-1.0	-1.2
Average Distance per Truck	5.5	2.2	-1.6	-1.7	-0.8	-1.1
Truck Diesel Use	15.4	4.7	4.1	4.0	1.8	2.3

Note: The numbers on this table have been rounded.

was marked by rapid growth in transportation energy use in response to high economic growth and declining real energy prices; the period from 1973 to 1980, which saw a reduction in growth in transportation energy use in response to reduced economic growth and rising energy prices; and the post-1980 period when transportation energy use actually declined under the impact of sustained increases in energy prices leading to a rapid improvement in fuel efficiencies of vehicle stocks.

During the period 1965 to 1973, transportation energy demand increased by six percent per year on average. Total motor gasoline use in the road sector increased by about six percent per year, whereas road use of diesel increased by 15 percent per year. The share of diesel in the road sector increased from three percent in 1965 to six percent in 1973. Over this period, the major determinants of road sector energy demand were:

- The number of cars on the road increased at an average rate of five percent per year, and cars per household increased from 1.00 in 1965 to 1.19 in 1973.
- The total stock of trucks increased by five percent per year reflecting the increasing role of light trucks as recreational vehicles.
- The stock of extra-heavy diesel trucks increased by 15 percent per year. This rapid growth resulted from a variety of factors such as the suitability of extra-heavy trucks in carrying high-value goods vis-à-vis the rail and marine modes, the dispersal of manufacturing activities from the core of major urban areas and the expansion of the highway network. This trend also continued through the seventies and into the early eighties.
- The average fuel efficiency of the vehicle stock (cars and trucks) remained essentially unchanged until the early seventies.

From 1973 to 1980, growth in transportation energy demand increased at an average annual rate of 3.5 percent per year. The reduction in growth relative to the pre-1973 period reflected mainly reduced growth in demand for motor gasoline, the major component of energy demand in this sector. In fact, road sector demand for diesel continued to increase at the same rate as that observed in the pre-1973 period. Lower growth in demand for gasoline relative to diesel in the road sector reflected the influence of a number of factors:

- Though the car stock increased by four percent per year, the impact of this increase on fuel use was, to a large extent, offset by improvements in the average fuel efficiency of the stock and by reductions in average distance driven per car. New car fuel efficiency improved by four percent per year during 1973 to 1980 reflecting fuel efficiency standards mandated by the Environmental Protection Agency (EPA) in the U.S. and the share of small cars in new car sales increased from 37 percent in 1976 to 56 percent in 1980.
- In the truck sector, gasoline demand growth was less than in the pre-1973 period reflecting a reduction in growth in the stock of gasoline trucks, a decline in distance per gasoline truck and improvements in the fuel efficiency of the truck sector. Reduction in growth in the stock of gasoline trucks resulted from reduced growth in the stock of light gasoline trucks combined with the dieselization of trucks in the medium/heavy categories. Fuel efficiencies of new gasoline

trucks also increased by one percent per year.

- In the extra-heavy diesel truck sector, truck stock growth continued to parallel growth in the manufacturing sector. The average distance travelled per diesel truck increased by five percent per year reflecting the increasing role of the heavy trucking sector in moving goods over longer distances. The increase in average distance also suggests that heavy diesel trucks made inroads in markets previously served by rail.

The period 1980 to 1986 witnessed a decline in transportation demand for energy by two percent per year. The decline encompassed all the sub-sectors. Motor gasoline use declined by 2.6 percent per year, partly offset by growth in road diesel use of some five percent per year. The relative growth rates of gasoline and diesel use reflected the influence of a number of factors:

- The car stock grew at less than half the rate observed during the period 1973 to 1980. Cars per household declined from 1.26 in 1980 to 1.20 by 1986.

- Average fuel efficiency of the car stock increased by four percent per year reflecting mainly improvements in the fuel efficiencies of new North American automobiles in the post-1976 period. A major reason for the improvement in new car fuel efficiencies was a reduction in weight. The average weight of domestic cars declined from 1735 kilograms in 1978 to 1373 kilograms in 1986. Technological improvements introduced during a period of increasing oil prices were being absorbed as the vehicle stock turned over so that, notwithstanding falling oil prices since 1981, fuel use per kilometre continued to decline.

- The shifts to smaller automobiles reinforced the impact of improvements in fuel efficiencies of individual model lines. The share of small cars in new car sales increased from 49 percent in 1978 to 75 percent in 1982 after which it fluctuated between 60 and 63 percent until 1987.

- Growth in the stock of gasoline trucks was more than offset by an increase in the average fuel efficiency of the stock. Consistent with EPA mandatory standards adopted in the U.S., the average fuel efficiency of new light gasoline trucks improved by 4.3 percent per year over the period 1980 to 1986.

- With regard to road diesel use, the impact of growth in the stock of extra-heavy diesel trucks on fuel use outstripped that in the average fuel efficiency of the stock. Most of the gains in fuel efficiencies were achieved through the use of radial tires and radiator fans, improvements to engine air intake and exhaust systems and reduction in aerodynamic drag. Average distance per diesel truck continued to increase as in the previous period.

In the two scenarios we are analysing, the high case has higher personal income growth, but higher oil prices; while the low case has lower personal income growth, but lower oil prices. Hence, in each case, income and oil price effects on demand tend to counteract each other, with the result that our projections of growth in transportation energy use differ only marginally between the high and low cases. We project transportation energy use to grow by 1.2 percent per year over the period 1986 to 2005 in the high case versus 1 percent in the low case. Total motor gasoline use increases by 0.6 percent per year in both cases with truck gasoline use increasing at a slightly higher rate than that of car gasoline. Road use of diesel fuel increases by 2.6 percent per year in the high case and by 2.2 percent per year in the low case.

Our projections of growth in car and truck use of energy are based upon our projections of growth in the **stock of vehicles**, the **average fuel efficiency** of the vehicle stock and the **average distance travelled** per vehicle.

We project cars per household to increase from 1.20 in 1986 to 1.35 in 2005 in the high case and to 1.30 in the low case. The projection assumes an increase in the proportion of car-owning households from 78 percent in 1987 to 88 percent in 2005. Our high case projection is consistent with the assumption that the proportion of one-car households will rise from 53.5 percent in 1987 to 60 percent by 2005, while that of multi-car households will increase from 24.6 percent in 1987 to 28 percent by 2005. Statistics Canada data shows that growth in income leads to an increase in the proportion of families owning one car as well as those owning two or more cars. The **stock of cars** will rise by 2 percent per year over the period 1986 to 2005 in the high case and by 1.8 percent per year in the low case.

We project technical **fuel efficiencies of new cars** to improve by 13 percent over the period 1986-2005 in the high case and by 10 percent in the low case. Based

on the recent experience of no improvement in the average sales-weighted fuel efficiency of new cars, some analysts foresee no increase or even a deterioration in the technical fuel efficiencies of new cars. However, we believe that it is not appropriate to draw inferences about new vehicle fuel efficiency on the basis of the average sales-weighted fuel efficiency of new cars, as the two measures are not the same. Our projections of improvement in new car technical fuel efficiencies are based on the following considerations:

- Although sales-weighted fuel efficiencies of new cars have changed little since 1983, our analysis indicates that technical fuel efficiencies have improved, albeit gradually, and the deterioration in sales-weighted fuel economy is due mainly to a shift towards heavier weight classes within and between the small and large car categories.

- During the period 1984 to 1986, despite significantly lower fuel prices in the U.S. than in Canada, the sales-weighted average fuel efficiency of new models in the U.S. improved by two percent per year. These improvements may be attributed to weight reduction through material substitution and the increasing use of electronic controls. Even luxury models have been made lighter by some 400 pounds. These major technological changes in vehicle characteristics, though based on U.S. conditions, will most likely be incorporated in vehicles sold in Canada, because of the integration in our car industries, and since Canadian fuel prices are higher than those in the U.S.

- Despite the fact that the easier and larger fuel efficiency improvements have already been achieved, there are still cost-effective technologies available which will produce further improvements. Examples of such cost-effective technologies related to the car body and drive train include reduction in weight through material substitution, reduction in average drag coefficient, use of overdrive transmission, introduction of low-profile radial tires and engine wear protection additives. Those related to the engine include the use of internal friction reducing devices and electronic controls. Application of electronic engine controls appears certain as vehicles require a microprocessor for emission control to meet revised pollution standards. Additions of other functions to the microprocessor should then become low cost options. Consumer reaction to most technologies should be favourable, since these offer increased performance and reduced maintenance. A favourable consumer response would facilitate acceptance of some increases in car prices which are likely to be modest in view of the existence of excess capacity in the automobile industry.

- While technological changes are made partly in response to variations in fuel price changes or consumer demand, such changes also result from competition between manufacturers to provide technologically superior and cost-effective products. We think a major reversal of consumer preferences which have developed over the last ten years is unlikely. Fuel-efficient technologies would, therefore, likely be introduced even when fuel prices are not increasing. Demand for more power in cars, introduction of pollution control devices and preference for options such as air conditioning may prevent fuel efficiency gains comparable to those of the last ten years. However, it does not seem likely that they would completely offset the technical gains discussed above, and we have assumed modest improvements.

We project little change in the **average distance driven per car**. Historically, average distance driven remained stable despite large increases of personal income; while growth of energy prices may be part of the explanation, habit is probably a more decisive factor.

The light duty truck market consists of pick-ups, vans and special purpose vehicles. These are generally used for both business and recreational purposes. Pick-up trucks have been used mainly on farms and by small businesses, while full-size vans have been used as people movers or service vehicles. Special purpose vehicles have unique features tailored to customer requirements, such as transportation vehicles for the disabled.

With the downsizing of automobiles, in the post-1976 period, vehicles in the light duty truck category have increasingly been substituted for full-size cars. The popularity of 4-wheel drive utility/sport vehicles and the attractiveness of downsized special purpose vehicles to former car buyers looking for cargo-carrying capacity in a comfortable vehicle stimulated sales of light duty trucks. Since 1983, a new market for minivans has developed as a substitute for large cars, station wagons and small business trucks. Several corporate automotive fleets and utilities are acquiring minivans. Some cities have

changed their taxi regulations to allow the use of minivans. The share of minivans in the light duty truck market increased from zero in 1983 to an estimated 25 percent in 1987.

We expect the light duty truck market to continue to adapt not only to fill the niche opened up by downsizing of automobiles, but also to accommodate changes in buyer preferences regarding function and comfort in vehicles, which will contribute to continued growth of their sales.

We project the **stock of light trucks** to increase by 3.4 percent per year in the high case and by 2.9 percent per year in the low case, in contrast to a growth of six percent per year during the period 1973 to 1986. Part of the reason for the lower projection is that the recent sales growth in vans reflected substitution for large autos and we expect a gradual saturation of this market. We also expect the growth in sales of vans and special purpose vehicles used as recreational vehicles to taper off relative to the historical period.

We assume the **average fuel efficiency of new light trucks** to improve by 0.8 percent per year over the period 1986 to 2005 in the high case and 0.7 percent per year in the low case. Many of the comments made above in this regard for cars apply also to light trucks.

With regard to road diesel use, we project the **stock of extra-heavy diesel trucks** to grow at 3.5 percent over the study period in the high case and 3.2 percent in the low case, much lower than the six percent annual growth observed during the period 1973 to 1986. The relatively lower growth in the extra-heavy diesel stock assumes better management of payloads in response to increased competitiveness in a deregulated environment. Provincial regulations have increased allowable lengths of truck-trailer combinations thereby increasing unit payloads. The share of manufacturing in RDP in the goods-producing sectors is also expected to rise less rapidly than in the past. The total stock of diesel trucks, however, increases more rapidly than that of extra-heavy diesel trucks as a result of the expected dieselization in the light duty truck market. Currently, almost 100 percent of light trucks are gasoline-powered. We have assumed the share of light diesels in total sales of light trucks to increase to 3 percent by 2005 in the high case and 2 percent in the low case. Cold-start problems and complaints regarding foul odors, driveability and performance have hampered the growth of light diesels.

It appears that the potential for improving **fuel efficiencies of extra-heavy diesels** is lower than that for cars and light trucks. We do not expect any significant improvements in fuel efficiencies of extra-heavy diesels. Manufacturers agree that future gains in heavy rig efficiency would come from on-board electronic systems which control the injection of fuel into the cylinder, monitor road speed and various systems on the truck (e.g. oil and water pressure, temperature and engine speed), and even operate shutdown/alarm and trip recording systems. The resulting improvements in fuel effi-

Table 4-10

Transportation Energy Demand

(Petajoules)

	1973	1986	1990 Case Low	1990 Case High	2005 Case Low	2005 Case High
Road	1181	1434	1478	1479	1730	1791
Gasoline	1106	1139	1130	1130	1268	1285
Diesel	75	274	321	319	416	446
Other	0	21	27	30	46	60
Air	126	163	185	184	192	208
Rail	101	75	88	88	102	107
Marine	132	75	84	82	94	91
Total	**1541**	**1747**	**1835**	**1832**	**2118**	**2198**
Fuel Efficiencies						
All cars (GJ/100 KM)	0.58	0.42	0.37	0.37	0.32	0.31
All trucks (GJ/100 KM)	0.96	0.88	0.79	0.79	0.70	0.68
Average Energy Use						
Per Car (GJ)	96	71	64	64	57	55
Per Truck (GJ)	250	208	188	187	162	156

Note: The numbers on this table have been rounded.

Table 4-11

Transportation Energy Demand and Intensities

Average Annual Growth Rates (Percent)

Energy Demand	1973-80	1980-86	1986-1990 Case Low	1986-1990 Case High	1990-2005 Case Low	1990-2005 Case High
Road	3.9	-1.2	0.8	0.8	1.1	1.3
Cars	2.5	-1.9	-0.7	-0.7	0.9	1.0
Trucks	6.0	-0.4	2.3	2.3	1.2	1.6
Air	4.5	-1.0	3.3	3.1	0.2	0.8
Rail	-1.0	-3.6	3.9	3.9	1.0	1.3
Marine	1.9	-11.0	2.9	2.2	0.8	0.8
Total	**3.5**	**-1.9**	**1.2**	**1.2**	**1.0**	**1.2**
Energy Intensities						
Energy Use per Car	-1.3	-3.5	-2.4	-2.4	-0.9	-1.0
Energy Use per Truck	-1.0	-1.9	-2.5	-2.7	-1.0	-1.2

Note: The numbers on this table have been rounded.

ciencies are, however, likely to be partly offset by increases in the length of tractor-trailers and requirements to meet more restrictive emission standards.

We have assumed fuel efficiencies of new extra-heavy diesel trucks to improve by 0.7 percent per year in the high case and 0.6 percent per year in the low case. This growth in new rig fuel efficiencies is about half that observed during the post-1978 period and partly reflects the fact that several cost-effective fuel-efficient technologies have already been introduced. This growth in efficiency is also lower than that in new light truck efficiency, consistent with historical experience.

We foresee limited growth in the market for propane and compressed natural gas (commonly referred to as NGV - natural gas for vehicles). The market for propane has matured; hence, we expect only modest growth in road use of propane. Rapid growth in the market for NGV has been hampered by the lack of readily available fuelling outlets. Federal and gas utility incentives combined with provincial governments' tax remissions may induce some fleets and delivery vehicles to convert to NGV. We project the share of propane and NGV in road energy use to increase from 1.3 percent in 1986 to 3.0 percent in 2005 in the high case and to 2.2 percent in the low case.

The *air transport sector* currently accounts for nine percent of the total transportation demand for energy. Energy use in the air transport sector increased at an average rate nearly twice the growth in GNP in the 1960s and early 1970s mainly as a result of the growing popularity of business and vacation air travel. Passenger kilometres grew at a rate three times the growth in GNP. Since the early 1970s, however, energy use in the air sector increased at a slower rate than the growth in GNP. This partly reflected slower growth in air travel and partly the introduction of fuel saving measures such as route rationalization, increase in load factors and technical improvements in engine and body design which improved fuel-efficiency per passenger-kilometre of aircraft.

We project energy use in the air sector to increase at 1.3 percent per year in the high case and one percent per year in the low case. These growth rates are less than half those in GNP in both cases. The projection reflects the view that growth in passenger-kilometres will be modest, partly as a result of the impact of telecommunications on business travel, and that load factors will continue to rise. As well, aircraft fuel efficiencies will continue to improve with the implementation of such measures as further engine modifications to existing aircraft, replacement of old aircraft by new more energy efficient fleets and improved air traffic control procedures. We project gains in aircraft fuel efficiency of about 1.5 percent per year over the study period.

There is considerable uncertainty about the impact on energy demand of deregulation of the air industry. Increased competition could lead to the use of even more fuel-efficient aircraft, but this could be offset by increased travel to perhaps a wider range of destinations.

Marine and rail transport is used mainly for carrying bulk goods such as grains, coal, iron ore and logs, though some manufactured goods are also carried by rail. These two sectors currently account for about five percent each of transportation energy demand. Consistent with recent experience we expect energy use to grow at a much slower rate than that of the economy. We project growth in energy use in the rail sector to be 1.9 percent per year in the high case and

1.6 percent per year in the low case. The corresponding growth rates for the marine sector are 1.1 percent and 1.2 percent.

It is possible that we have not sufficiently accounted for the impact of the revisions to the Crow's Nest Pass grain freight rates. The new measures will increase the capacity of the rail system; hence, energy use could be somewhat greater than we have projected. Rail electrification on a major scale seems unlikely; the high cost of rail electrification and the uncertainty with respect to government financial assistance have made railway companies unwilling to make firm commitments to electrification.

Table 4-10 shows the disaggregation of transportation energy demand into car, truck, air, rail and marine sector demand. Table 4-11 shows average annual growth rates for these major transportation sector aggregates. Figure 4-2 illustrates the changing distribution of energy use for each of the five transportation sectors.

Summary

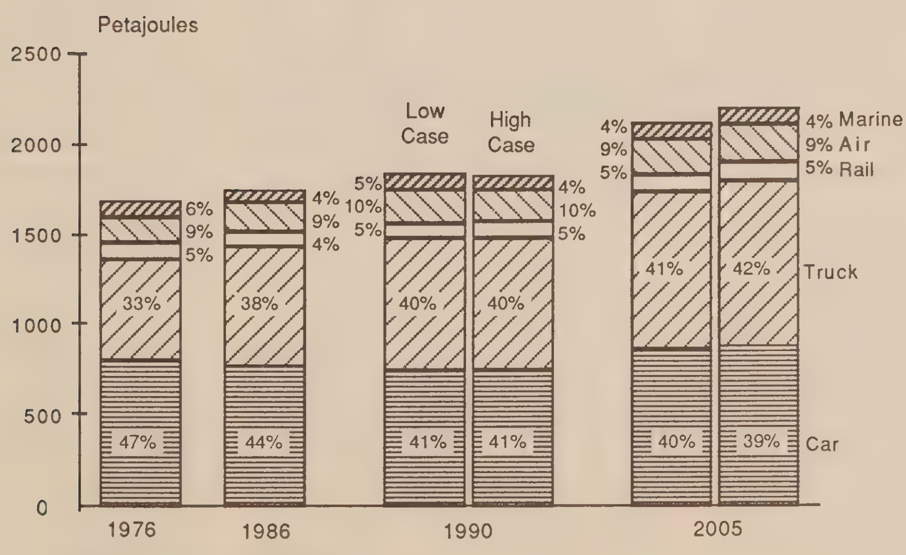
Total end use demand for the low and high cases is shown in Figure 4-3. Sectoral distribution of demand for only the low case is shown in this figure, differences in sectoral energy use between the two cases are discussed below. End use demand grows at 1.4 percent annually in the low case and 1.8 percent in the high from 1986 to 2005. In 2005, end use demand in the high case is 9 percent greater than that of the low case, as the positive impact of higher economic activity more than offsets the negative impact of higher oil prices, relative to the low case. As discussed in Section 4.1.1 prices of natural gas and electricity are broadly similar in the two cases, while high case oil product prices are some 20 to 50 percent higher in 2005 than those in the low, the size of the difference depending on the type of product.

Both projections show steady declines in energy intensity - of 0.7 percent annually in the low case and 1 percent in the high. Differences in sectoral energy demand between the two cases reflect our assumptions of the impact of economic activity and price on the sectoral energy demands, as well as assumptions of changes in the efficiency of energy use in each case.

The main differences in the sectoral demands in the two cases are:

- Residential demand is three percent lower in the high case relative to the low in 2005. Higher incomes are expected to increase the rate of improve-

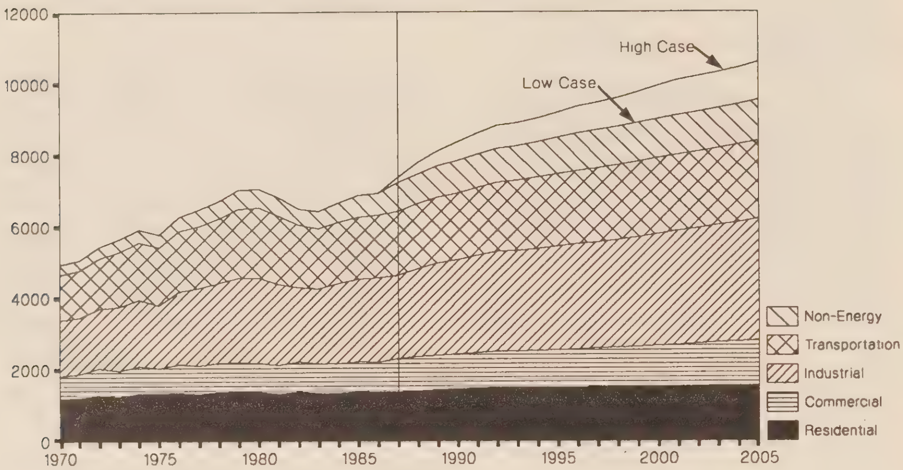
Figure 4-2
Distribution of Transportation Demand by Sector



Source: Appendix Table A10-1.

Figure 4-3
Total End Use Energy Demand

Petajoules



Source: Appendix Table A4-4.

ment in energy efficiency which offsets other income effects, such as increased penetration of new appliances. These gains lead to less demand in the high case, as there is no difference in the number of households between the two cases (Section 4.1.2).

- Commercial end use demand is three percent higher in the high case than the low; as in the high case we expect growth in commercial sector output to more than offset the stronger efficiency gains in this case.

- Industrial energy demand shows the largest variation between the two cases, with demand 23 percent greater in the high case than in the low by 2005. This results from our assumptions that total industrial output is 21 percent higher, and output of energy-intensive industries 25 percent above that in the low case in 2005. Industrial energy demand accounted for 35 percent of end use demand in 1986; in 2005 it accounts for 37 percent and 42 percent of end use demand in the low and high cases respectively.

- Transportation requirements are four percent higher in the high case, as a larger stock of cars and trucks (due to higher income and output levels) more than offsets the more rapid fuel efficiency improvements (in response to higher oil prices) relative to what happens in the low case. The transportation sector accounts for 63 percent of end use demand for oil.

- Non-energy use of hydrocarbons is only marginally higher in the high case, due to greater use of asphalt. Demand for petrochemical feedstock does not differ between the two cases.

In our October 1986 Report our high oil price case had lower economic growth than our low case. Thus in the high oil price case, high energy prices and low economic growth reinforced each other in terms of their negative impacts on energy demand. The low oil price case combined lower energy prices and higher economic growth both stimulating energy demand. End use demand in the low oil price case was 10 percent higher in 2005 than it was in the high oil price case. In this (1988) report, high case demand is about 9 percent higher than low case demand, because higher income in aggregate more than offsets the negative impact of higher prices; higher income is a key characteristic of the high case.

In the October 1986 Report, industrial output and total gross domestic product were respectively 8 percent and 6 percent higher in the low price case by 2005. In this 1988 report they are 21 percent and 15 percent higher in the high case than in the low by 2005.

The inset table shows differences between the two cases' energy demand by sector for the 1986 and for the 1988 reports.

4.2 End Use Energy Demand by Fuel and Region

Fuel use varies considerably across regions, reflecting the availability and use of natural gas, and relative energy prices of each region. As seen in Figure 4-4 and Table 4-12, the absence of natural gas in the Atlantic region results in a larger share of oil used for non-transportation purposes. In Quebec, where electricity prices are lower than in many other provinces, and where there is less acceptance of natural gas for residential uses, the share of electricity is almost twice as high as else-

Differences in End Use Energy Demand by Sector in 2005
(percent)

	1986 Report[1] High Growth/ Low Growth	1988 Report[2] High Growth/ Low Growth
Residential	8	-3
Commercial	12	3
Industrial	10	23
Transportation	14	4
Non-Energy	1	1
Total	10	9

1. High growth was associated with low oil prices in the 1986 Report, and low growth with high oil prices.
2. High growth is associated with high oil prices in the 1988 Report, and low growth with low oil prices.

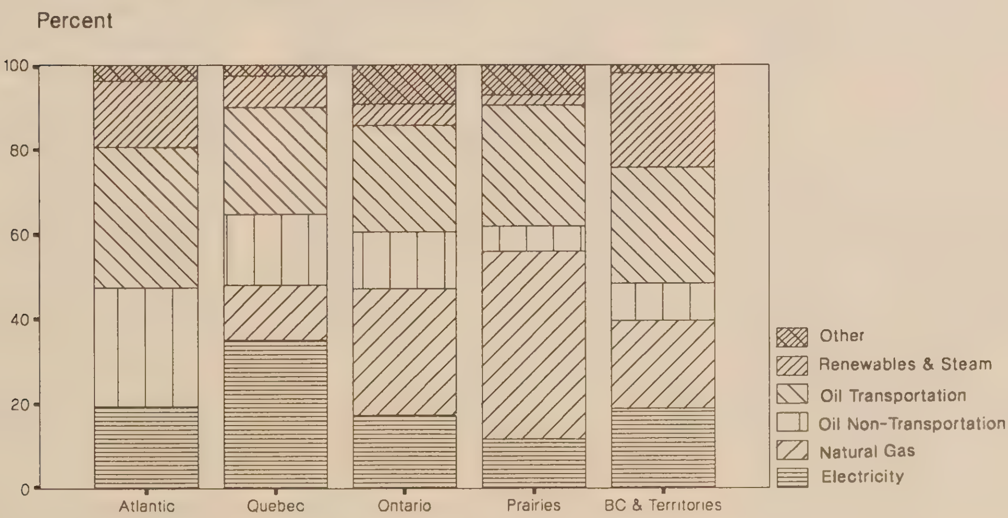
where in the country. Ontario's large industrial use of natural gas, combined with high penetration of this fuel into the residential and commercial sectors make natural gas the most important fuel in that province. In the Prairies, natural gas dominates, although on a provincial basis electricity has an important role in Manitoba's non-transportation fuel use. British Columbia's reliance on wood wastes for its pulp and paper industry is the main reason for the relatively high share of renewables in that province.

On a regional basis, we have not assumed major changes to the existing network of fuel distribution, for example we have not included natural gas in the Atlantic region, or a natural gas pipeline to Vancouver Island.

Table 4-13 shows the levels of total energy demand by region in 1986 and 2005 for both cases. Ontario accounts for approximately 35 percent of end use demand in Canada - a share that does not change in our projections. The pattern of growth in end use energy demand closely reflects the pattern of economic growth, except in Alberta where bitumen demand in the high case causes Alberta's energy demand to grow more rapidly.

Renewable energy has strong regional concentration as shown in Figure 4-4. We discuss below our outlook for the role of alternative energy, followed by a more detailed discussion of fuel demand by region.

Figure 4-4
End Use Fuel Shares by Region in 1986



Source: Appendix Table A4-6.

Table 4-12

End Use Fuel Shares by Region 1986

(Percent)

	Atlantic	Quebec	Ontario	Prairies	B. C. and Territories
Electricity	19	35	17	12	19
Natural Gas	-	13	30	44	21
Oil Non-Transportation	28	17	13	6	9
Oil Transportation	33	25	25	28	27
Renewables[a] and Steam	16	7	5	2	22
Other[b]	4	3	9	7	2
Total	**100**	**100**	**100**	**100**	**100**

Notes: The numbers on this table have been rounded.

[a] Renewables includes wood, wood waste, solar, wind and municipal solid waste.

[b] Other includes coal, coke, coke oven gas and natural gas liquids.

Table 4-13

End Use Energy Demand by Region

	(Petajoules)			Average Annual Growth (Percent)	
	1986	2005 Case		1986-2005 Case	
		Low	High	Low	High
Atlantic	504	629	693	1.2	1.7
Quebec	1435	1867	1979	1.4	1.7
Ontario	2469	3278	3502	1.5	1.9
Manitoba	243	299	306	1.1	1.2
Saskatchewan	278	341	371	1.1	1.5
Alberta	1171	1470	1858	1.2	2.5
British Columbia	885	1133	1166	1.3	1.4
Canada	**6986**	**9018**	**9876**	**1.4**	**1.8**

Note: The numbers on this table have been rounded.

4.2.1 Alternative Energy

We use the term alternative energy to refer to renewable sources - such as wood, wood wastes, solar and small-scale wind - and non-conventional sources such as municipal solid waste.

In 1986, these sources accounted for just under eight percent of Canada's end use energy requirements. Of the total 522 petajoules of alternative energy, 78 percent, or 410 petajoules, was wood waste used in the pulp and paper sector, and 21 percent represented wood use in the residential sector.

Measuring use of alternative or renewable energy in the residential and commercial sectors poses certain difficulties. In some instances, wood or solar may not be the primary source of energy. Use of passive solar or infrequent use of wood may be measured as conservation (as it reduces requirements for conventional, measured energy sources) rather than as alternative energy consumption. Thus it is likely that our estimates understate the use of some of these alternative energy forms, although their impact on the use of conventional non-renewable energy sources is captured in our projections.

The demand for alternative energy will be influenced by how all forms of energy are priced. Essentially, there are two bases of cost accounting according to which prices may be determined. One is "social cost accounting", wherein the price of energy would recover not only direct costs of production, but also other costs which the production of this energy imposes on parties other than the producers of the energy. An example is the pollution cost of fossil-fueled power plants, or the loss of fishing benefits from any disruptive impacts of a

hydro dam. Pricing based on social cost would account for all of these factors; it would not include subsidies, and it would reflect the social cost of the next unit of energy to be produced.

The other basis of pricing is commercial cost accounting, which reflects how the market place views supply costs and determines market prices, given current taxes and subsidies. On this basis, market prices include the energy suppliers' direct production costs, any subsidies received, taxes paid, and may reflect a mixture of incremental and historical costs.

The relationship between the prices of alternative energy and conventional energy could differ if energy were priced on the basis of social costs rather than on a commercial or market basis. We use the market pricing approach, because our primary objective is to estimate demand and supply of energy in the context of anticipated market price behaviour.

Given our outlook for oil, natural gas and electricity prices, our projections show very little change in the share of alternative energy forms. Except for the use of wood in the residential sector and wood waste by industry, existing technology for most alternative energy is still expensive compared with that of conventional energy, when priced on a market basis. Therefore, the share of these energy sources does not increase. We recognize, however, that pricing mechanisms and tax policies could change, as could individual preferences in favour of using alternative energy forms. There may also be technological breakthroughs which enhance the viability of alternative energy. These factors could increase the share of these energy sources to levels higher than we have projected.

The wood waste share of industrial end use demand rose from 12 percent in 1977 to 17 percent in 1986; however, by 2005 that share is projected to decline to between 12 and 14 percent. The declining importance of wood waste as a source of energy for industrial output is due to the pulp and paper industry's falling share of industrial gross domestic product and to its increased use of thermomechanical pulping (TMP).

Encouraged by rapidly rising oil prices between 1973 and 1981 and the Canadian Oil Substitution Program (COSP), residential wood use increased to capture 8 percent of total residential energy use by 1986. In the Atlantic region and in Quebec the increase was more dramatic as wood use rose to 25 percent and 12 percent respectively of residential end use demand. For the outlook period, the real world oil price is not projected to reach its 1981 level and in the absence of further government incentives, the wood use share of residential energy demand grows from eight percent in 1986 to 8.5 percent in 2005.

Municipal solid waste can be burned to produce steam for process heat or to generate electricity or it can be a source of biogas for subsequent use in heating buildings or generating electricity. Biogas, consisting mostly of methane, carbon dioxide and hydrogen sulphide, is now being extracted from a municipal landfill site in Richmond, British Columbia and burned in a kiln at Canadian Cement Lafarge. The landfill gas provides about 13 percent of the energy requirements of the kiln. If not extracted and properly burned it is a dangerous pollutant. Negotiations are underway to extract methane gas from a municipal solid waste site at a quarry near Montreal for heating Montreal municipal offices.

The decision to build a municipal solid waste plant is only partly influenced by the price of alternative fuels. Another factor is the increasing difficulty of finding suitable and environmentally acceptable dumpsites in the larger urban areas. Our projections include about 20 PJ of energy from municipal solid waste in commercial and industrial uses by 2005. This is three percent of alternative energy use, and does not vary between scenarios; we feel that non-price factors will largely determine the use of this technology.

Small power projects based on alternative energy are being tested and may be economic in remote communities; one example is Canada's first windfarm which was recently built at Cambridge Bay, Northwest Territories.

In both the high and low cases we project that alternative energy sources will account for about 7 percent of Canada's total end use energy demand by 2005, compared to their 7.6 percent share in 1986.

4.2.2 Atlantic Region

The Atlantic region has access to virtually no natural gas. Fuel choices are mainly oil and electricity in all sectors, wood waste and coal in the industrial sector and wood in the residential sector. Since the oil price shocks of the 1970s, this region has made major reductions in its dependence on oil, largely through increased use of wood and wood waste.

End use demand in the Atlantic region is projected to increase by 1.2 percent annually in the low case and by 1.7 percent in the high case over 1986 to 2005. Improvements in energy intensity of 0.6 and 0.9 percent per year are expected in the low and high cases, respectively.

In our projections, we anticipate a continued decline in oil's share of the region's end use demand from 61 percent in 1986 to 57 percent in 2005 in the high case and to 59 percent in the low case. All of this decline occurs in the use of oil for non-transportation uses; the share of oil for transportation use is stable at close to 33 percent of total end use energy.

By 2005, our projections show electricity's share at 25 percent in the high case and 22 percent in the low case, up from 19 percent in 1986, as the residential, commercial and industrial sectors increase their electricity use in both cases.

Given the relatively low oil prices of the two scenarios (as compared to oil prices of the mid-1970s to early 1980s) we have not allowed for major increases in the share of wood for residential heating, which remains at 25 percent of the sector's needs in both cases. Physical resource constraints and increased use of thermo-mechanical pulping reduce the share of renewables in Atlantic industrial demand. As a result, renewables energy use in 2005 accounts for 14 percent and 13 percent of end use in the low and high cases respectively, down from 16 percent in 1986.

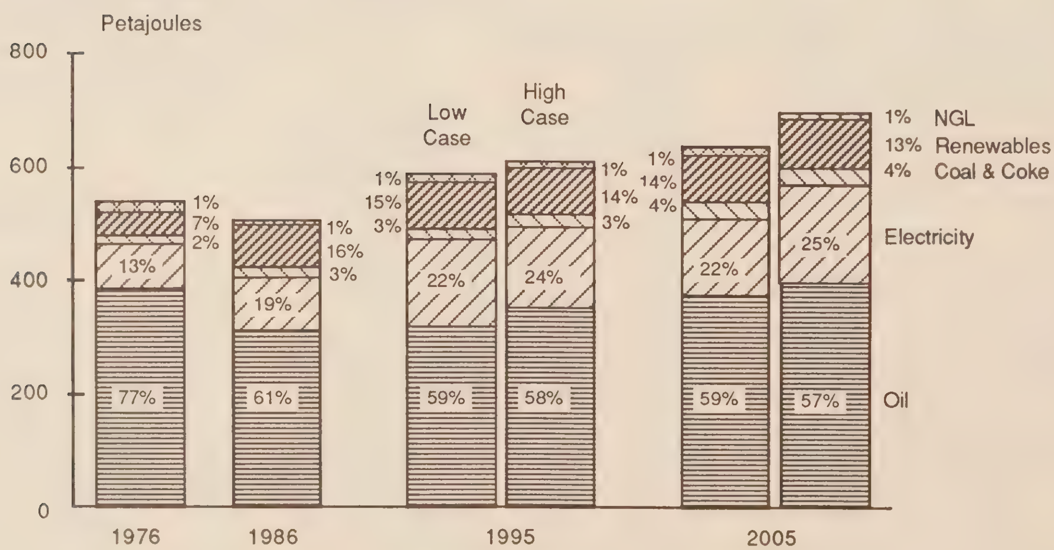
The projected levels and shares of end use demand (including transportation demand) for the Atlantic region are shown in Figure 4-5.

4.2.3 Quebec

During the 1970s and early 1980s there was intense competition between natural gas and electricity to capture both new markets and conversions from oil. While this competition has lessened, Hydro-Québec is still pursuing incentive programs for certain industrial markets. As a result the flexibility of fuel choice in industrial plants exceeds that of any other Canadian province, with many plants able to select heavy fuel oil, natural gas or electricity. Moreover, approximately five percent of the housing stock in Quebec has dual heating capability.

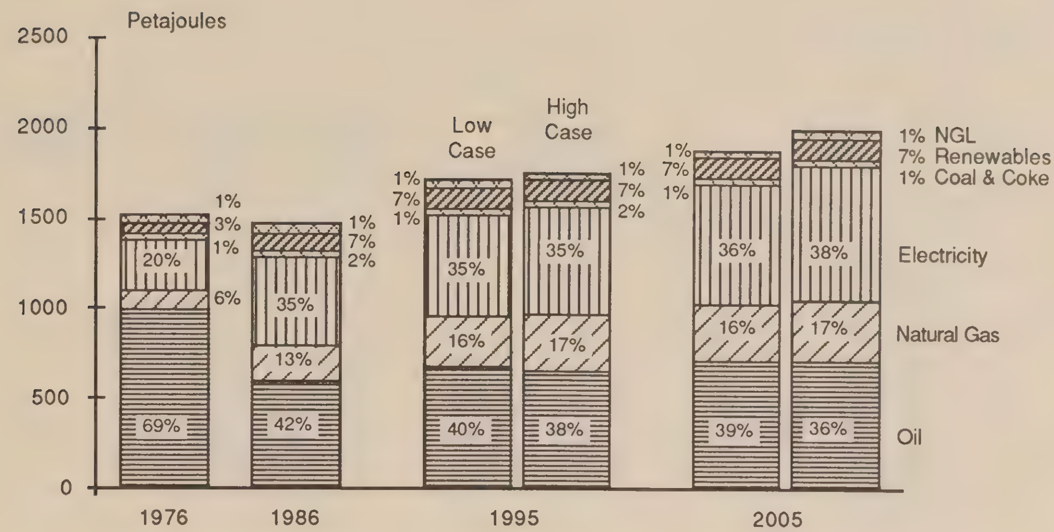
Fuel switching will depend more on relative prices than on continuing subsidies or incentives, as any new incentive programs are expected to be very limited.

Figure 4-5
End Use Energy Demand by Fuel
Atlantic



Source: Appendix Table A4-6.

Figure 4-6
End Use Energy Demand by Fuel
Quebec



Source: Appendix Table A4-6.

Quebec's requirements for end use energy are projected to increase by 1.4 percent annually in the low case and by 1.7 percent in the high over the period 1986 to 2005. Energy use per unit of output declines on average by 0.8 and one percent per year in the two cases.

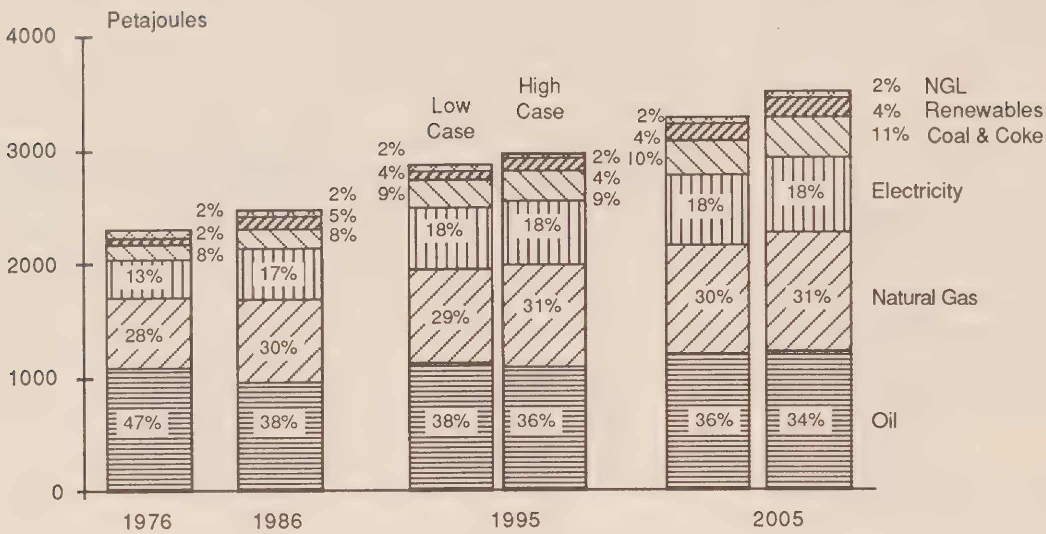
Given the importance of electricity use in the province and the expectation that consumer preferences will limit natural gas growth in the residential sector, fuel shares change very little. In the low case we have assumed continued, though slow, conversion off oil, which reduces the non-transportation oil share of end use energy from 17 percent in 1986 to 14 percent in 2005, with natural gas and electricity capturing this market. In the high case, the oil share for non-transportation declines from 17 percent in 1986 to 13 percent in 2005, and electricity accounts for 38 percent of end use demand by 2005, up from 35 percent in 1986. Oil used for transportation purposes maintains close to 25 percent of the market in both cases.

4.2.4 Ontario

Ontario's end use demand grows more rapidly in both cases than that of any other province, with the exception of Alberta in the high case. The province's energy requirements increase by 1.5 percent annually in the low case and 1.9 percent in the high, although energy intensity declines by just under one percent annually in the low case and about 1.3 percent per year in the high, from 1986 to 2005. The province's industrial sector accounts for much of this growth. This sector's demand grows by 2.5 to three percent annually in the high case, and its share of Ontario's energy use rises from 33 percent in 1986 to 39 percent by 2005. In the low case it accounts for 35 percent of the province's energy demand in 2005, reflecting industrial energy demand growth of just under two percent per year.

There is little difference in fuel shares between the two cases or through time. The 1986 share of electricity was 17 percent and our projections show that level maintained in both cases, reflecting the impact of Ontario Hydro's proposed demand management on growth in electricity demand. Without this program the share of electricity would have been slightly higher. Oil's share declines slightly from 38 percent in 1986 to 34 percent in the high case and 36 percent in the low case in 2005. This decline is largely in non-transportation use, as we have assumed continued conversions off oil, and that new markets will use mainly natural gas or electricity. This trend is more marked in the high case, given higher oil prices.

Figure 4-7
End Use Energy Demand by Fuel
Ontario



Source: Appendix Table A4-6.

Natural gas - at 30 percent of demand in 1986 - maintains a stable share through 2005 in the low case, and shows only a slight increase (to 31 percent) in the high case (see Figure 4-7).

4.2.5 Prairie Provinces

Our projections show end use demand in the Prairie region growing at 1.2 percent annually over 1986 to 2005 in the low case and 2.1 percent in the high case. Alberta accounts for seventy percent of the region's energy use, and thus dominates any trends at the regional level. The increasing demand for coal and natural gas for energy-intensive bitumen projects results in only a small improvement in projected aggregate energy intensity in the two cases.

In 1986, oil used for non-transportation purposes accounted for only six percent of end use demand. The total share of oil was 34 percent. This share declines to 29 percent in 2005 in the low case and 26 percent in the high because oil used in transportation grows relatively slowly.

Transportation energy demand grows less rapidly in this region than in other parts of the country, as car and truck stock fuel efficiencies improve more rapidly (older vehicles are being replaced) and as the stock itself grows less rapidly, reflecting the fact that the number of cars per household is already much higher than in other regions of the country and is assumed to increase less rapidly than elsewhere.

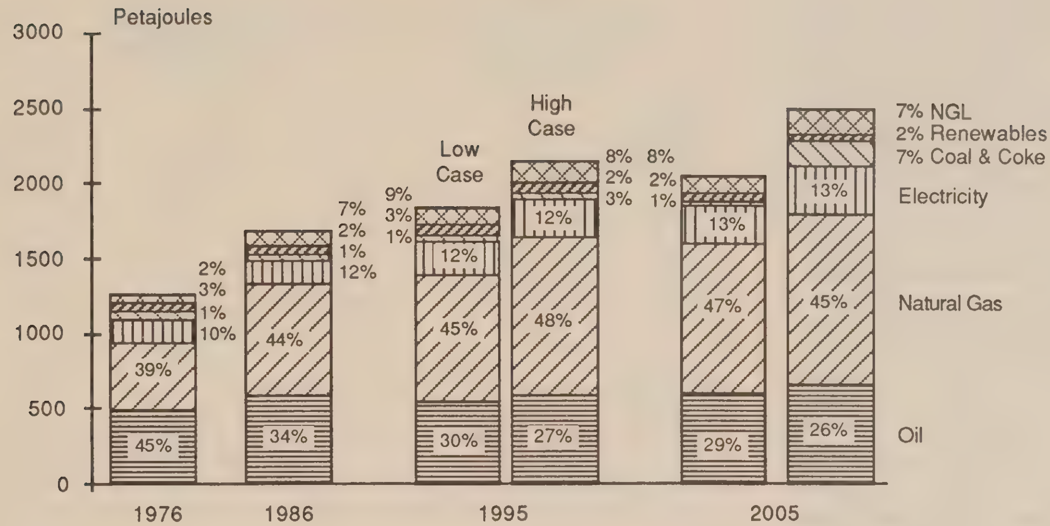
The pattern of fuel shares is affected by the assumptions concerning coal use in bitumen projects in the high case. Coal's share increases from under one percent in 1986 to almost 8 percent in 2005 in this case; its annual average growth is 19 percent over the projection period. In the low case, there is no requirement for coal in bitumen production and coal demand grows at only 6 percent over 1987 to 2005 and its share increases to just over one percent, reflecting requirements of the cement industry, which are included in both cases.

4.2.6 British Columbia, Yukon and Northwest Territories

British Columbia's end use energy demand is projected to grow from 1986 to 2005 at 1.3 percent annually in the low case and at 1.4 percent in the high case. Though the growth is similar in the two cases, energy intensity declines more rapidly in the high case (at just over one percent per year) than in the low case (0.8 percent per year).

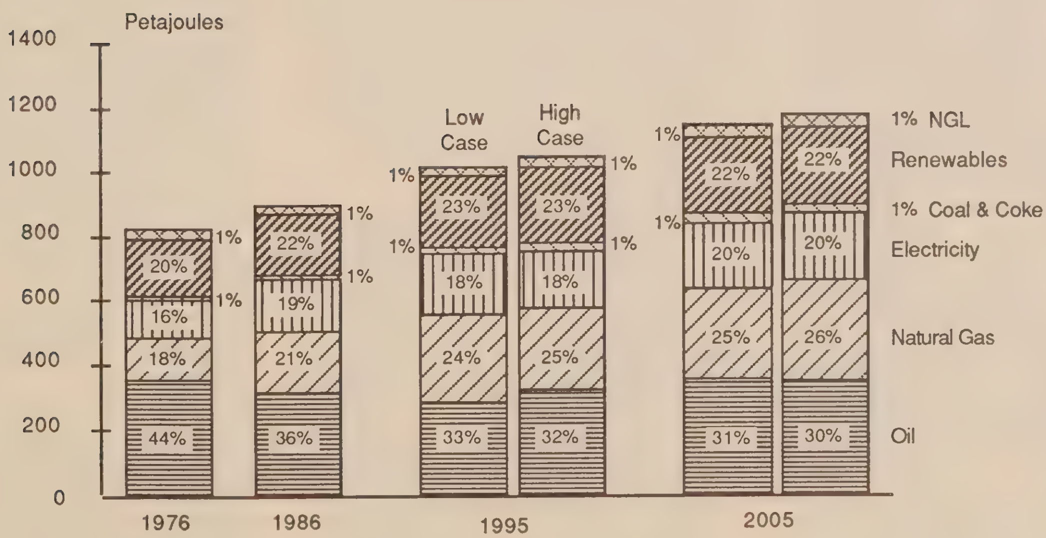
By the year 2005 fuel shares for British Columbia are very similar in the high and low cases. Over the

Figure 4-8
End Use Energy Demand by Fuel
Prairies



Source: Appendix Table A4-6.

Figure 4-9
End Use Energy Demand by Fuel
BC & Territories



Source: Appendix Table A4-6.

projection period there is only a small increase in electricity's share - from 19 percent in 1986 to about 20 percent in 2005, in part reflecting our assumption that B.C. Hydro introduces demand management. Oil for non-transportation uses accounted for only 9 percent of provincial demand in 1986, and is expected to decline to about 6 percent by the year 2005 in both cases. Oil for transportation use is projected to decline from 27 percent of total energy use to between 24 and 25 percent in 2005 for similar reasons as discussed for the Prairies.

Renewables, dominated by wood waste, maintain about 22 percent of provincial energy demand in both cases. As the pulp and paper sector faces resource constraints in the future and as wood waste is replaced by electricity, we do not expect any increase in the role of wood waste in meeting the province's energy needs.

Yukon and the Northwest Territories rely on oil and electricity for all of their energy use.[1] There have been some recent small scale projects using wind but the bulk of energy needs are still met through conventional sources. We do not anticipate any changes in the fuel mix. However, small-scale renewable projects may take on a more important role in the future.

4.2.7 Canada

End use energy demand in Canada grows by 1.8 percent in the high case and 1.4 percent in the low case, as energy intensity declines annually by one percent and 0.8 percent respectively over 1986 to 2005.

As shown in Table 4-14 and Figure 4-10, we expect fuel shares to remain relatively stable through 2005. The major exception is the oil share which decreases in both cases, reflecting continued, slow, switching away from oil. The doubling of coal's share over the projection reflects our specific assumptions regarding coal use for bitumen recovery, discussed in Section 9.3. Shares of electricity and natural gas rise slightly[2].

The differences in end use by fuel in the two cases (see inset table on following page) result from the sectoral differences in total energy requirements (Section 4.1) and changing fuel shares in those sectors. In summary:

- Oil end use is only one percent higher in 2005 in the high case than in the low. Oil used by the transportation and industrial sectors is higher, but is offset by reduced demands by residential and commercial consumers.
- Electricity and natural gas are 11 and 12 percent higher respectively in the high case than in the low in 2005, reflecting mainly the stronger demands of the industrial sector, and to a lesser extent the commercial sector. Residential use of these fuels does not differ between the two cases.
- Use of renewables shows little difference; we do not think that

Table 4-14

End Use Energy Demand and Fuel Market Shares

	(Petajoules)			Differences
	1986	2005 Case		[a]
		Low	High	
Levels				
Electricity	1389	1902	2119	11
Natural Gas	1856	2550	2846	12
Oil	2766	3241	3328	1
Renewables[b]	554	654	669	2
Coal	241	404	636	57
NGL	179	266	279	5
Total	6986	9018	9876	9
		(Percent)		
Shares				
Electricity	20	21	21	0
Natural Gas	27	28	29	1
Oil	40	36	34	-2
Renewables[b]	8	7	7	0
Coal	3	5	6	1
NGL	2	3	3	0
Total	100	100	100	

Notes: The numbers on this table have been rounded.
[a] Difference for levels is high minus low as percentage of the low case.
Difference for shares is the percentage point difference of shares, high minus low.
[b] Includes hog fuel and pulping liquor, wood, solar, municipal solid waste and steam.

1. The territories are included with British Columbia to be consistent with Statistics Canada reporting of economic variables.
2. In our October 1986 Report our projections showed an increasing share of natural gas and electricity, mainly at the expense of oil.

Differences in End Use Energy Demand by Fuel in 2005
(percent)

	1986 Report[1] High Growth/ Low Growth	1988 Report[2] High Growth/ Low Growth
Electricity	2	11
Natural Gas	13	12
Oil	16	1
Renewables and Steam	1	2
Coal	11	57
NGL	-2	5
Total	10	9

1. In the October 1986 Report high growth was linked to low oil prices, while low growth was associated with high oil prices.
2. In the 1988 Report we assume that high world growth (and consequently high Canadian growth) would be conducive to high oil prices, while in our low growth case we have low oil prices.

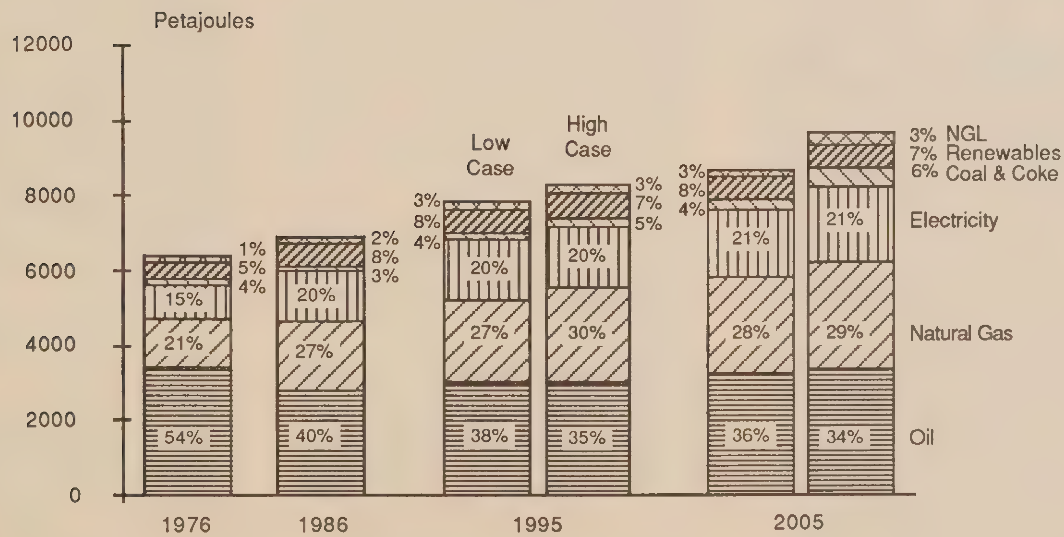
the energy prices in our high and low cases will be conducive to increased penetration of these energy forms.

- Bitumen use of coal is the major factor behind the large difference in coal demand between the two cases.

- Natural gas liquids use differs only slightly between the two cases, partially due to our assumption of higher demand for propane for transportation use in the high case. We have not assumed any difference in petrochemical feedstock use of natural gas liquids between the two cases (Section 4.1.5).

While the difference between our two cases for end use energy

Figure 4-10
End Use Energy Demand by Fuel
Canada



Source: Appendix Table A4-6.

demand is similar to that of the October 1986 Report, the differences for each fuel are not similar and reflect sectoral demands as discussed in Section 4.1. The inset table compares the differences by fuel between the two cases of each report.

4.3 Primary Energy Demand

4.3.1 Primary Demand for Oil

Primary demand for oil consists of the quantities of refined products required for end use, own use and conversions. End use requirements - the use of oil products for non-energy purposes and for the residential, commercial, industrial and transportation sectors - constitute the largest component of primary oil demand. Oil products used by the energy supply industry and the requirements for electricity and steam production make up the remaining share of primary oil demand.

The composition of primary oil demand by product is similar for the two cases (Table 4-15). Between 1986 and 2005:

- the share of light fuel oil and kerosene declines considerably;
- the share of diesel fuel oil increases, but that of motor gasoline falls.

The evolution of primary demand for light fuel oil and kerosene during the projection period can be directly attributed to the continuing loss of market share of these fuels in the residential and commercial sectors to natural gas and electricity. The reduction in oil demand in the residential and commercial sectors is shown in Table 4-16. During the study period, light fuel oil and

Table 4-15

Distribution of Primary Oil Demand by Product

(Percent)

	1986	1990 Case		2005 Case	
		Low	High	Low	High
Aviation Fuels	5	6	6	5	6
Motor Gasoline	36	34	34	34	33
Light Fuel Oil and Kerosene	10	7	7	5	4
Diesel Fuel Oil	19	21	21	22	24
Heavy Fuel Oil	9	10	9	10	9
Asphalt	4	4	4	4	5
Other	16	18	18	19	19
Total	**100**	**100**	**100**	**100**	**100**

Note: The numbers on this table have been rounded.

Source: Appendix Table A4 - 8.

Table 4-16

Primary Demand for Oil by Use

(Petajoules)

	1986	1990 Case		2005 Case	
		Low	High	Low	High
Sectoral Demand					
Residential	273	232	232	195	164
Commercial	104	96	93	90	81
Industrial	313	329	324	326	372
Petrochemical	127	169	169	219	219
Transportation	1726	1808	1802	2072	2138
Other Non-energy	223	257	260	340	354
Total End Use	**2766**	**2891**	**2880**	**3241**	**3328**
Own Use and Conversions					
Energy Supply Industry[a]	209	220	221	252	260
Electricity Generation	60	67	85	137	130
Steam Production	2	2	2	2	2
Butanes Used for Blending	-27	-31	-31	-31	-32
Refinery LPG	58	60	60	68	71
Total Own Use and Conversions	**301**	**318**	**337**	**427**	**431**
Total Primary Demand	**3066**	**3210**	**3217**	**3668**	**3759**

Notes: The numbers on this table have been rounded.
[a] Includes refinery LPG own use.

Source: Appendix Table A10-1.

Table 4-17

Primary Demand for Natural Gas

(Petajoules)

	1986	1990 Case Low	1990 Case High	2005 Case Low	2005 Case High
End Use	1856	1959	2116	2550	2846
To generate electricity[a]	61	71	79	138	144
Pipeline fuel and loss	129	160	167	198	213
Reprocessing fuel	18	22	23	26	28
Primary Demand[b]	**2064**	**2211**	**2386**	**2913**	**3231**

Notes: The numbers on this table have been rounded.
[a] Natural Gas used to produce steam included.
[b] Excludes reprocessing shrinkage.

Source: Appendix Table A10-1.

kerosene requirements for the two sectors combined decrease by 3 and 4 percent annually in the low and high cases respectively.

The increase in the share of diesel fuel oil in primary oil demand and the decrease in that of motor gasoline originate in the transportation sector. More rapid growth in the distance driven by diesel vehicles compared with gasoline vehicles in both cases, combined with less improvement in the efficiency of diesel vehicles, cause diesel fuel oil requirements for transportation to rise by 2.1 and 2.4 percent annually from 1986 to 2005 in the low and high cases respectively. Motor gasoline requirements increase by 0.6 percent annually in both cases, which is less than the growth of total primary oil demand.

Overall, primary demand for oil from 1986 to 2005 increases by 0.9 and 1.1 percent annually in the low and high cases respectively (Table 4-16). Of all end use sectors, transportation is the largest. Throughout the projection period in both cases, transportation accounts for 56 percent of primary oil demand.

In 2005, primary demand in the high case is 91 petajoules or 2.5 percent higher than in the low case. Since the total of own use and conversions is almost the same in the two cases in 2005, the difference in primary demand stems mainly from end use requirements for oil products; transportation accounts for more than 75 percent of this difference.

4.3.2 Primary Demand for Natural Gas

As is the case for oil, end use demand accounts for the largest share of primary natural gas demand (Table 4-17). Primary demand for natural gas also includes the fuel required to produce steam and electricity, and to operate pipelines and reprocessing plants.[1]

During the projection period, primary demand for natural gas increases at average annual rates of 1.8 percent in the low case and 2.4 percent in the high. These growth rates are similar to those of end use requirements.

Natural gas used to generate electricity is for domestic requirements only and is used mainly in the industrial sector rather than by electrical utilities. The extent of this use of natural gas depends on end use demand for electricity and how this electricity is generated. In 1986, Alberta used more than 40 petajoules and was the province where the greatest amount of natural gas was used for electricity generation; national requirements totalled 60 petajoules. During the projection period Alberta remains the principal user of natural gas for electricity generation, accounting in 2005 for 61 and 69 petajoules of the Canadian totals of 138 and 144 petajoules in the low and high cases respectively.

Pipeline fuel and losses are related to the transportation of natural gas for export, and to the transmission and distribution of gas to meet domestic requirements.

The amount of natural gas required for the transportation of exported natural gas increases gradually until 1992, and then remains constant until 2005 in both cases. In 1986, these transportation requirements amounted to 27 petajoules; a level of 52 petajoules annually is projected for the years 1992 to 2005, reflecting our outlook for natural gas exports.

1. For purposes of the analysis presented in this chapter, natural gas consumed as a result of reprocessing shrinkage is excluded from primary demand for natural gas and is instead included in primary demand for natural gas liquids, discussed in Section 4.3.3. However, the reverse is true in Chapters 6 and 10 where the supply/demand balance for energy is discussed.

Fuel required for the transmission of natural gas to domestic markets increases from 71 petajoules in 1986 to 100 and 110 petajoules in 2005 in the low and high cases respectively, average annual increases of 1.8 and 2.3 percent. The amount of natural gas used for distribution to end users is lower than the amount required for transmission. From 32 petajoules in 1986, distribution requirements increase to 47 petajoules in 2005 in the low case and to 51 petajoules in the high.

4.3.3 Primary Demand for Natural Gas Liquids

Table 4-18 provides primary demand for natural gas liquids (NGL) by use. For purposes of primary demand analysis, natural gas liquids are defined to include only propane, butanes and ethane.[1] Propane and butanes are produced by gas plants and refineries, and ethane is a by-product of natural gas. Although these hydrocarbons may come from different sources, their end use is reported in aggregate. However, in moving to primary demand, propane and butanes produced by refineries are excluded, as they are treated as part of primary oil demand. Thus, the primary demand for ethane and gas plant NGL amounted to 151 petajoules in 1986. Growth in demand results in levels in 2005 of 233 petajoules in the low case and 244 petajoules in the high.[2]

As with oil and natural gas, end use requirements constitute the main component of primary demand for NGL. Ethane, which is used as a petrochemical feedstock, accounts for about 50 percent of the total end use for NGL. From 1986 to 2005, ethane demand increases by 3 percent annually in both cases. Propane and butanes for non-energy use, and propane used in the transportation sector also contribute to increased NGL end use demand. From 1986 to 2005, end use demand for total NGL increases at an annual rate of 2.1 percent in the low case and 2.4 percent in the high case. The annual growth of the residential, commercial and industrial NGL use is below that of total end use. The difference between primary demand in the two cases in 2005 results mainly from propane used in the transportation sector.

Table 4-18

Primary Demand for Natural Gas Liquids[a]

(Petajoules)

	1986	1990 Case Low	1990 Case High	2005 Case Low	2005 Case High
End Use Demand	179	204	207	266	279
Propane and Butanes	96	110	114	127	139
Ethane	84	94	94	140	140
Own Use and Conversions	37	43	43	46	48
Energy Supply Industry	10	12	13	15	16
Butanes Used for Blending	27	31	31	31	32
Sub-total	**217**	**247**	**251**	**312**	**327**
Less Refinery LPG[b]	65	70	70	79	83
Primary Demand for Ethane and Gas Plant NGL	151	177	181	233	244

Notes: The numbers on this table have been rounded.
[a] Excludes pentanes plus. Pentanes plus are included in crude oil.
[b] End use demand assumed to be met by refineries.

Source: Appendix Table A10-1.

4.3.4 Primary Demand for Coal

In addition to end use demand, the primary demand for coal includes requirements for the production of steam and electricity, own use and conversion of coal into coke (Table 4-19).

Unlike other fuels, the main component of primary coal demand is not end use demand; rather it consists of requirements for the generation of electricity, especially in Alberta, Ontario, Saskatchewan and Nova Scotia. Coal used for conversion to coke is the second largest component of primary

1. Pentanes plus are included with crude oil and are therefore excluded here.
2. Note that ethane is treated here as a component of primary demand for NGL. However, in the analysis of the supply/demand balance for energy in Chapter 10, primary ethane requirements are included in the primary demand for natural gas.

Table 4-19

Primary Demand for Coal
(Petajoules)

	1986	1990 Case Low	1990 Case High	2005 Case Low	2005 Case High
End Use Demand[a]	56	59	63	89	265
Electricity Generation[b]	796	686	792	1087	1292
Steam Generation	1	0	0	0	0
Other Conversions and Own Use	3	6	6	9	11
Coal to Coke Conversion	184	228	243	332	390
Primary Demand	**1040**	**978**	**1104**	**1517**	**1958**

Notes: The numbers on this table have been rounded.
[a] Excludes coke and coke oven gas.
[b] Fuel for electricity exports included.

Source: Appendix Table A10-1.

demand. Coke is used by the iron and steel industry.

From 1986 to 2005, primary demand for coal increases at average annual rates of 2.0 and 3.4 percent in the low and high cases respectively. The substantially higher rate of increase in the high case is the result of increased requirements for the generation of electricity, in addition to the use of coal in bitumen production in Alberta. We assume in the high case that coal will be used for bitumen production beginning in 1995, along with natural gas. In the low case, only natural gas is used. This results in the widening range in end use demand for coal between the two cases from 1995 to 2005.

4.4 Concluding Comments

Our projections are based on two specific outlooks about the overall growth rate of economic activity and the distribution of the resulting output between energy-intensive and other industries, and on an analysis of the efficiency of energy use under the price and income settings of each macroeconomic projection.

There is considerable uncertainty both about how the economy might evolve and how energy consumers will react to any specific set of economic factors.

We have done a rough assessment of the sensitivity of our end use demand projections to some of the more critical assumptions affecting energy demand.

Our assumption that the industrial sector's share of total output will increase over the projection period is contrary to the outlook of many analysts. If the shares of industrial and commercial output were maintained at their 1986 levels, we estimate that total end use demand would be two to four percent, or about 150 to 400 petajoules, lower by 2005.[1]

As discussed in Section 4.1.4, energy-intensive industries within the industrial sector account for a very high proportion of industrial energy demand, though their share of the sector's production is only about 25 percent. As we noted, the share of energy-intensive industries in total industrial output declines slightly over the study period in our projections. If there were no decline in this share, industrial energy demand would be approximately five percent or 450 petajoules higher by 2005.

We project ongoing improvement of energy intensity, resulting from our analysis of technical change, conservation and increasing efficiency in the use of energy. If we were to assume no change in energy intensity relative to the 1986 level, by 2005 industrial energy demand would be about 15 percent or 500 to 550 petajoules higher. Commercial energy demand would be between 15 to 25 percent (or 180 to 250 petajoules) higher. These calculations - with no change to our estimates of demand in the other sectors - would lead to an increase in total end use demand of about 7 percent, or 700 to 800 petajoules.

For the transportation sector we have examined two basic assumptions relating to car energy demand - no change in car stock fuel efficiencies relative to 1986 levels and no change in the number of cars per household from 1986 levels. Each of these

1. This simple calculation uses the same energy intensities as in our high and low cases (which implies the same relative importance of energy intensive industries), includes no change in the demand of other sectors, and most importantly assumes that the aggregate output level of the two cases could be achieved with the 1986 distribution of industrial and commercial output.

impacts assumes no change in other related variables. If there were no change in the car stock fuel efficiency from 1986 levels, by 2005 car energy demand would be about 35 percent or close to 300 petajoules higher. If we maintained the same number of cars per household as in 1986 (and were able to still maintain the same car stock fuel efficiency as given in the main assumptions for our two cases) car energy demand would be 11 percent or about 100 petajoules lower.

There are major uncertainties about the prospects for energy demand growth which relate to the prospects for the industrial distribution of economic activity and for energy efficiency and conservations gains. On balance we think there is a greater risk that energy demand growth may be higher than we have projected over the next fifteen years rather than lower; given the efficiency and conservation gains we have built into our estimates. However, major structural changes reflecting worldwide environmental concerns could, conversely, lead to even greater gains in efficiency and conservation than we have included.

Chapter 5

Electricity

The objective of this chapter is to highlight the main characteristics of the Canadian electricity industry and the changes required in electricity production to meet our projected demand in the context of a rapidly changing and uncertain business and technological environment, notably in the areas of interprovincial and export trade and non-utility production.

We first describe the principal implications of our electricity demand projections (Section 5.1). We then assess the prospects for electricity trade between provinces and with the United States and discuss the environmental implications of exports. This leads to a discussion of the need for new generating capacity in each province, and of the timing of major projects, taking into account the effect of demand management and the contribution of non-utility producers. Finally we present our projections of total electricity production and the need for fossil fuels, hydro and nuclear energy resources.

The total demand for electrical energy in each province is calculated by converting the end use demand projections from Chapter 4 from petajoules to gigawatt hours. Part of this demand is met by minor utilities and industrial generation. We then calculate the major utility total firm commitments by adding the estimates of utilities' own use and losses, firm interprovincial sales, and firm exports. This total demand for elecuical energy is used in conjunction with information on the utilities' generation expansion plans to project the supply scenario for each province.

We simulate the planning and annual operation of the major provincial utilities in order to project fuel requirements and the timing of capacity additions, taking into account the required reserve capacity, so that the total peak demand and energy requirements, including interprovincial firm commitments and projected firm potential exports, are met in every year.

Surplus production capability is then determined as the difference between projected total annual average capability and total firm energy requirements. The resulting surplus is assumed to be available for out-of-province sales on an interruptible basis. Consistent with the aim of maximizing the economic gains from interconnected operation, we have assumed that energy surpluses would be sold on the basis of transactions between markets with the lowest and highest incremental costs.

Utilities supply most Canadians with electricity. Their mandate is to ensure that adequate supplies of electricity are made available to reliably meet the needs of their firm customers at the least cost. Utilities therefore routinely forecast their customers' requirements for periods of fifteen to twenty years, to take into account the long lead times required for major projects. This sets a framework for the orderly planning and construction of new generating plants and transmission facilities, and the acquisition of the required fuels and other resources needed to meet the anticipated demand.

Due to the high costs of new facilities and because of environmental constraints imposed upon the siting and construction of new generating plants and transmission lines, utilities are increasingly seeking to manage demand rather than solely trying to meet it by building new installations. This study reflects our discussions with utilities on their plans for managing demand.

Privately-owned industries, institutions, and some individuals also produce electricity. We project that in some provinces they will assume a greater role in supplying electricity. In general, utilities are increasingly ready to buy electricity from non-utility producers at prices which reflect the utilities' own avoided production costs and under conditions compatible with sound system operations. Some provinces are even considering calling upon the private sector for proposals to supply electricity as a supplement to utility expansion.

Most of the provincial governments and electric utilities already have, or will soon establish, policies dealing with non-utility generation. British Columbia, Alberta, Ontario and Quebec have identified the potential for non-utility supplies. In

general, we have used assumptions consistent with these policies where information was available; in other provinces no specific assumptions have been made. More details are set out in Section 5.3.

Surpluses in generating capability may result when anticipated loads do not materialize or when an economic advantage can be gained over the long term by capacity additions larger than short-term increases in demand might justify. These surpluses are made available first to neighbouring Canadian utilities and then to interconnected utilities in the United States. Sales of these surpluses, largely on an interruptible basis, have in the past formed the bulk of interprovincial and international transactions.

Several provinces are now increasingly seeking firm export markets and are willing to pre-build[1] new facilities to serve export loads. Some notable early examples of this trend are New Brunswick's firm export of electricity from the Point Lepreau I nuclear plant, firm energy export contracts recently concluded by Quebec and a firm power export from Manitoba.

Although there are many different kinds of transactions which form an almost continuous spectrum of available services, we have, for simplicity, segregated electricity transactions into two broad classifications, interruptible and firm, depending on whether or not delivery is guaranteed. We made a further distinction between sales in which productive capacity (power) is reserved for the purchaser and sales where the delivery is primarily of bulk electricity (energy without guaranteed capacity).

In order to provide a realistic outlook of export transactions, we have included estimates of export sales based on potential transactions, some of which are not yet confirmed and for which the NEB has not granted an export licence. This is essential if we are to provide a realistic estimate, as most existing export licences terminate within the study period. However, this assumption is without prejudice to NEB decisions on specific applications. A detailed discussion of these assumptions is contained in Section 5.2.

Interprovincial transactions of electricity have taken place for many years to take advantage of the benefits which can be gained by interconnecting systems: reserve sharing, improved reliability and economy exchanges for example. Our projections include ongoing interprovincial trade for example between Newfoundland and Quebec, Quebec and New Brunswick, and Alberta and British Columbia (see Figure 5-5).

Although our projections of exports and interprovincial transactions reflect assumptions which we consider to be the most plausible, there are several instances where realistic alternative assumptions could also be made. Accordingly, we present in Section 5.6 an alternative supply scenario based on assumptions of higher levels of electricity exports and more interprovincial electricity trade than in the two main cases.

5.1 Domestic Electricity Demand

The Canadian electric power industry has grown rapidly from small hydro plants serving isolated loads in the early 1900s to today's vast interconnected electric power networks with total installed generating capacity in excess of 95 000 megawatts[2] from a variety of generating sources.

After several decades of growth in electricity demand at annual rates of about 7 percent, demand growth fell steadily from the mid-1970s until very recently, as a result of the slowdown in economic growth and other economic factors which accompanied the oil price shocks. By the late 1970s, annual electricity demand growth rates averaged close to 3 percent. In 1987 electricity demand in Canada increased by 3.5 percent from 1986 levels. While this continues the trend of moderate load growth rates, in some regions growth rates have exceeded this level in recent years; in Ontario, energy demand increased 4 percent in 1987 from 1986 levels.

Table 5-1 contains our electricity demand outlooks expressed in terawatt hours.

Table 5-1 also contains our projections of the annual peak power demand (i.e. the highest level of power demanded in the year) for each province and region. These have been calculated from the energy demand outlooks of Chapter 4 by projecting utility load factors (the ratio of average to peak load) based on historical data and on our expectations with regard to peak load management by utilities. At present, load factors typically

1. Pre-building involves construction in advance of the timing required to serve domestic needs.
2. The units most commonly used for electrical energy and power (i.e. the capacity used to produce electricity) are multiples of kilowatt hours (kW.h) and kilowatts (kW) respectively. The multiples of these units used in this report are gigawatt hours (GW.h), terawatt hours (TW.h), megawatts (MW) and gigawatts (GW). (See Appendix Table A1-1).

Table 5-1

Domestic Electricity Demand by Province [a]

Electrical Energy Demand

	Energy Demand (Gigawatt hours) [c]			Rate of Growth (percent/year)	
	1986	**2005**		**1986 to 2005**	
		Low Case	**High Case**	**Low Case**	**High Case**
	(1)	(2)	(3)	(4)	(5)
Newfoundland	9834	13238	20688	1.6	4.0
Prince Edward Island	607	932	966	2.3	2.5
Nova Scotia	7950	11604	12789	2.0	2.5
New Brunswick	11555	18154	19899	2.4	2.9
Quebec	152626	202934	223917	1.5	2.0
Ontario	127031	171778	184947	1.6	2.0
Manitoba	16222	23003	23857	1.9	2.1
Saskatchewan	11947	16799	19133	1.8	2.5
Alberta	34800	47269	60979	1.6	3.0
British Columbia	49494	67715	71128	1.7	1.9
Yukon	344	423	479	1.1	1.8
Northwest Territories	618	847	906	1.7	2.0
Total Canada	**423028**	**574696**	**639688**	**1.6**	**2.2**

Peak Demand [b]

	Peak Demand (megawatts)			Rate of Growth (percent/year)	
	1986	**2005**		**1986 to 2005**	
		Low Case	**High Case**	**Low Case**	**High Case**
	(6)	(7)	(8)	(9)	(10)
Newfoundland	1820	2375	3625	1.4	3.7
Prince Edward Island	109	172	178	2.4	2.6
Nova Scotia	1469	2127	2341	2.0	2.5
New Brunswick	2199	3147	3440	1.9	2.4
Quebec	27274	35388	39246	1.4	1.9
Ontario	21569	27914	30093	1.4	1.8
Manitoba	3082	4320	4492	1.8	2.0
Saskatchewan	2129	2973	3386	1.8	2.5
Alberta	5322	7774	9574	2.0	3.1
British Columbia	7830	10411	10978	1.5	1.8
Yukon	69	80	91	0.8	1.5
Northwest Territories	120	161	172	1.6	1.9
Total Canada	**72992**	**96842**	**107616**	**1.5**	**2.1**

Notes: The numbers in this table have been rounded.
[a] Excludes export sales.
[b] Peak Demand is the sum of non-coincident peak loads in each service area and therefore overstates the actual peak.
[c] Converted from petajoule values in section 4.1 using conversion factor of 3.6 petajoules per terawatt hour.

range between 60 and 70 percent. We assume that in most provinces, efforts to shift consumption from peak to off-peak times (peak load management) will cause load factors to gradually increase by as much as 5 percentage points in some provinces over the study period.

The projections in Table 5-1 also take into account the effects of increasing amounts of demand management whereby provincial utilities provide incentives to their customers to promote the efficient use of electricity by encouraging the use of more efficient appliances, motors, lights and equipment and the implementation of higher building insulation standards.

We project growth in electricity demand at an average annual rate of 1.8 percent in the low case and 2.6 percent in the high case until 1990, and at annual rates of 1.7 percent and 2.3 percent in the two cases respectively between 1990 and 2005.

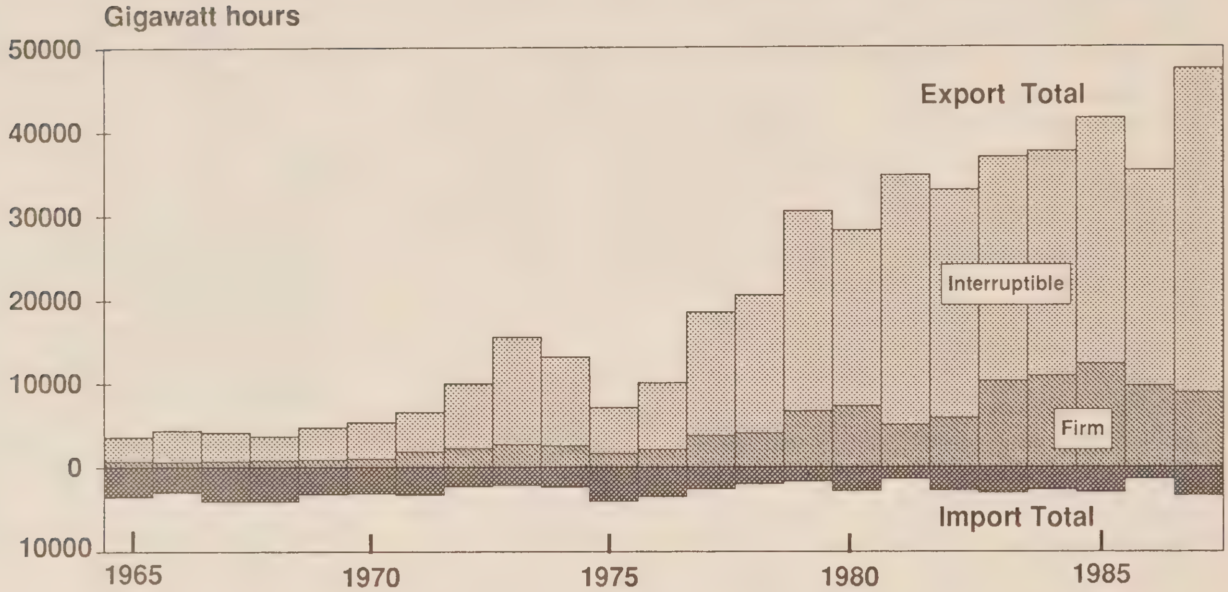
5.2 Exports

In Canada, provincial transmission networks were initially developed in isolation, with the exception of Ontario, which established international power lines in the early 1900s. As opportunities arose, interties between neighbouring systems were established, initially along north-south lines and more recently between provinces, to gain improved reliability and cost reduction in system operations.

Figure 5-1 shows the evolution of international trade in electricity since 1965.

Figure 5-1

Annual Exports and Imports of Electricity



Up to the early 1970s, exports and imports were approximately in balance. The completion of generating plants which had been committed before 1973 in response to expected high load growth rates, made available a substantial quantity of surplus capacity by the mid-1970s, much of it hydro- and coal-based. This surplus found a ready market in the U.S. given the rapidly increasing cost of oil-based generation.

Gross exports[1] have increased from 10.4 terawatt hours in 1972 to about 47 terawatt hours in 1987. The rapid increase reflects the availability of Canadian energy at prices which have been attractive to U.S. utilities, and a technological and regulatory environment which has adapted quickly to the needs of changing markets.

Firm exports (about 29 percent of the total net exports in 1986) have been used by U.S. utilities to postpone investment in new plants, to provide reserve capacity and also to provide emergency support. In all cases, the economic and operational benefits of trade have been shared between Canadian and U.S. utilities.

In addition to operational and economic effects, electricity exports have environmental impacts in both countries. In Canada, most of the electricity destined for export is produced from hydro or nuclear resources. These, in general, have impacts which are highly localized and relatively benign.

The exported energy is used to avoid burning fossil fuels in the U.S., thereby reducing air pollutant emissions and the associated problems such as acidic deposition and diminished air quality. Ontario is the major exporter of energy produced by burning fossil fuels, mainly coal. This energy is used in the U.S. market to displace fossil fuels, so that the incremental acid gas emissions produced in Ontario are roughly offset by reductions of these in the U.S.

The balance of electricity exports are made by the provinces of New Brunswick, Quebec, Manitoba and British Columbia mainly using hydro and, particularly in the case of New Brunswick, nuclear energy sources.

In 1990, New Brunswick and Quebec's exports to New England and New York are projected to

1. Gross exports are the total amounts exported without consideration of returning flows or imports. Net exports in 1987 were 44 terawatt hours.

account for about 10 percent of fossil fuel-based production in that region, resulting in a proportionate reduction in acid gas emissions. Similarily, in 1990, Manitoba's exports will reduce the emissions from coal-burning plants in its market region by about 1 percent and British Columbia's exports will allow a 5 percent reduction in emissions in its U.S. market. On balance, exports have a beneficial environmental impact.

Electricity trade patterns between North American utilities have evolved in a regionalized pattern. Each region corresponds to an aggregation of utilities which are tightly interconnected. This regional structure is reflected in the North American Electric Reliability Council (NERC) and its member regions. In the regional councils of NERC, Canadian utilities join with those in the U.S. to promote reliable power supply and to coordinate standards of planning and operation.

From the perspective of exporting Canadian utilities, the U.S. market comprises five distinct areas. These are illustrated in Figure 5-2, which also shows the projected interconnection capacity with those markets in 1990[1]. New Brunswick exports to New England; Quebec to both New York and New England; Ontario to the Michigan-Ohio Valley area and New York; Manitoba to Minnesota and North Dakota, Saskatchewan to North Dakota, and British Columbia to Washington, Oregon and California.

New England is served by many relatively small utilities. The region consists of six states, each with its own regulatory commission. The result is that building major new capacity additions or transmission lines is complicated, requiring a high degree of interutility and interstate co-ordination. This is facilitated by pooling arrangements and a co-operative approach to solving supply problems.

New England has limited indigenous resources for power generation and is heavily reliant on coal, uranium, and, particularly, oil, because of the latter's historic availability at low cost and convenience. However, coal use is subject to increasingly stringent environmental constraints, nuclear plants have met with widespread public opposition, and the cost of oil-based generation varies with the world oil price.

Although utilities had been planning for more modest load increases, New England's load has been growing more quickly than anticipated over the past several years. Many existing generating plants are small and are reaching the end of their design lives; already, parts of New England have experienced capacity reserve shortfalls in the summer peak period. However, because of an uncertain regulatory climate, many U.S. utilities are reluctant to commit themselves to building major new generating plants, as they are expensive capital projects with long lead-times. Utilities in New England have increasingly sought new methods of supplying their customers' loads and have been more willing to consider long-term firm purchases from other U.S. suppliers and Canadian utilities.

Non-utility suppliers are emerging. Industrial co-generators and independent power producers are offering generating capacity with short construction lead-times, frequently fueled by natural gas.

The New York market, like that of New England, is served by numerous utilities. Although some of them serve large loads, most serve small areas. As a result, New York shares some of New England's problems of market fragmentation and difficulties in building transmission lines and generating plants. Although both areas have pooling arrangements to co-ordinate system operating and planning practices, New York, unlike New England, has a large state-owned utility, the New York Power Authority, which controls the bulk transmission network and which is directly interconnected with Quebec. As a result, the New York Power Authority has been the principal purchaser of Quebec's exports to New York, acting on behalf of the several utilities in the state. This arrangement has worked effectively, enabling New York to take advantage of opportunities for electricity trade.

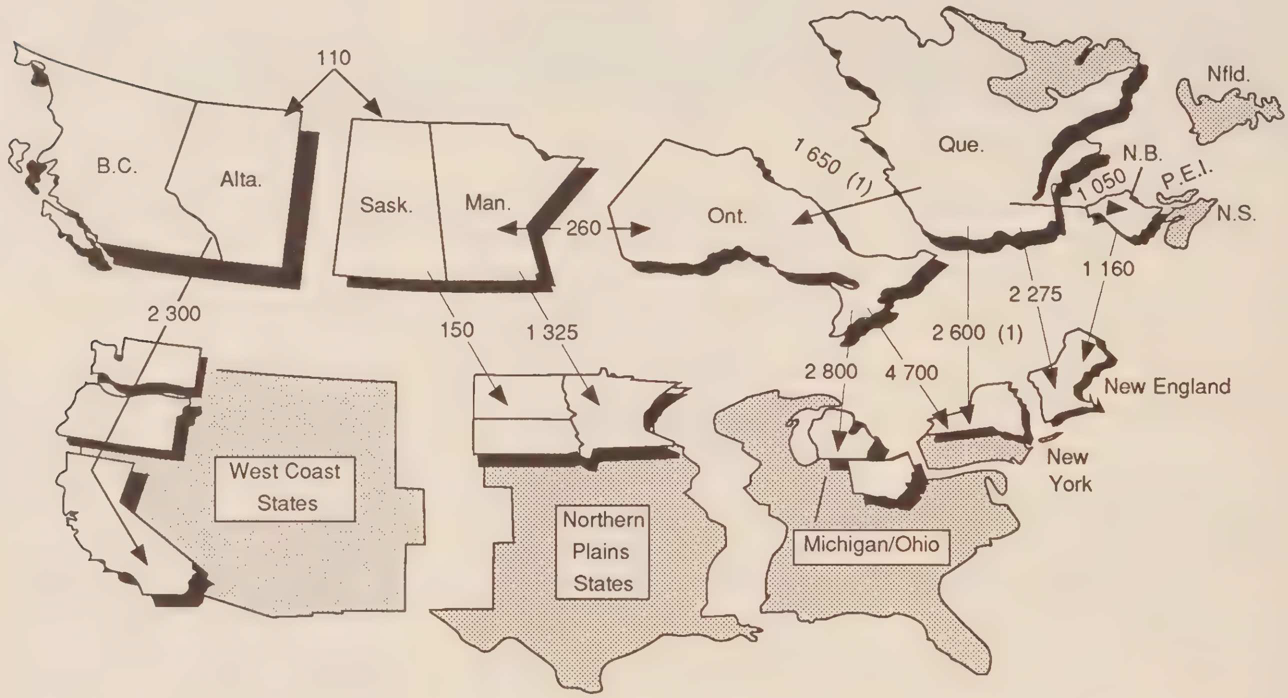
Although it is in a better supply position than New England, New York is nonetheless heavily reliant on older oil- and coal-fired plants and will likely need additional sources of supply by the mid-1990s. Utilities in New York are also reluctant to commit to the construction of major new generating plants and are looking to long-term purchases from neighbouring U.S. and Canadian utilities, such as Quebec, as a secure and economic future source of supply.

Michigan and Ohio have an excess supply at the present time, and will not likely require substantial amounts of capacity until late in the 1990s. Abundant reserves of local coal provide an economical and reliable future supply of fuel. Environmental protection restric-

1. The interconnection capacity is an approximate value only. The actual capacity varies continually with system conditions.

Figure 5-2

Canadian Exporting Regions and United States Export Markets.
Projected Approximate Interconnection Capacity(2)
1990



Notes: (1) Simultaneous transfer capacity to Ontario and U.S. is 3 310 MW.

(2) Interconnection capacity is dependent on the state of the interconnected systems at any given time and varies continually. For this reason an approximate value is shown.

tions will add to the cost of burning coal on both sides of the border in this region. New coal-burning technologies such as fluidized bed boilers and improved environmental control equipment are expected to provide more economical ways of burning coal in an environmentally acceptable manner.

The Minnesota, North Dakota and South Dakota region is not likely to need much new capacity until the mid-1990s and is presently well supplied from coal-burning plants which have access to an abundant low-cost, lignite resource. U.S. utilities' access to this resource reduces the attractiveness of purchasing Manitoba's electricity since the economies to be gained are more modest than in other market regions where the alternatives for the U.S. utilities are more costly and the needs more pressing.

Washington, Oregon and California constitute the potential export market for Alberta and British Columbia; the largest of these is in southern California. California utilities, while not likely to need major new capacity additions until the mid-to-late 1990s, are heavily dependent on a large number of small gas- and oil-fired generating stations and on privately owned generating units, many of which are gas-fired.

Utilities in southern California face regulatory uncertainty, stringent environmental regulations and a burgeoning independent power-producing sector which is increasingly able to supply the region's growing loads. As well, issues such as security of supply for a system dependent on premium fuels and reliability of supply from the large number of non-utility participants, place additional burdens on utility planners. As a result, utilities are averse to making major capital investments in new plants. While western Canadian utilities may wish to supply more to this growing market, their access to the long and heavily loaded north-south transmission lines belonging to the Bonneville Power Administration (BPA) has been restricted. BPA has given preferred access to its own surpluses and to those of neighboring U.S. utilities, thus precluding British Columbia or Alberta from making long-term firm exports.

This policy was recently revised to give British Columbia increased access to the north-south tie. Access would be granted in return for integrating the operation of British Columbia's system more closely with the BPA, or in return for other considerations to be negotiated. Under the terms of the Canada-U.S. Free Trade Agreement, British Columbia will be granted the same access as U.S. extra-regional utilities[1] to spare capacity on the tie.

The north-south tie is expected to be expanded in the next few years. At the same time, the hydro surpluses of utilities in the U.S. northwest, which compete with those of British Columbia, are expected to decline as their own demand grows. As a result, access for British Columbia to the California market is assumed to improve.

5.2.1 U.S. Regulatory Environment for Canadian Exports

Canadian electricity exports and construction of international power lines may be affected by U.S. federal and state regulatory authorities.

- The Economic Regulatory Agency (ERA) of the Department of Energy administers the issuance of presidential permits for the construction and operation of international power lines. A permit must be sought for any change in use or operation of an international power line. This, in effect gives the ERA broad control over electricity imports.

  A presidential permit requires concurrence of the Secretary of State with respect to the trade implications and of the Secretary of Defence regarding any national security implications. As well, if a project has the potential to cause environmental damage, an Environmental Impact Statement may be required.

- The Federal Energy Regulation Commission (FERC), regulates:
  - rates charged by investor-owned utilities for interstate resale of electricity including imported electricity,
  - rates for transmission services used in interstate electricity trade, and
  - rates charged by federal power marketing bodies, such as the Bonneville Power Administration, for the sale of capacity, energy, and transmission services.

- State regulatory boards have a mandate to minimize the cost of service to consumers, while setting fair rates of return on capital for utilities. As a result they can

1. Extra-regional utilities are those which are not partners in the ownership and operation of the north-south intertie.

affect the marketability of Canadian energy through the rates they set and through their determination of the extent to which the U.S. importing utility may recover payments to the Canadian exporter.

Regulation of the U.S. electric power industry is currently undergoing considerable re-examination based on the premise that a more competitive market structure would be conducive to increasing supply at least cost to the consumer. New business practices, such as sales to utilities by non-utility power producers, competitive bidding for supply to utilities, and more open access to transmission networks, are being proposed to create a competitive climate. To this end, the FERC issued Notices of Proposed Rulemaking in March, 1988 which solicited comments on proposals to introduce a competitive bidding process for incremental supplies of electricity and to streamline the regulation of independent power producers.

In the last few years, several U.S. utilities have been subjected to state regulatory reviews of the prudency of capital investments in facilities made to serve anticipated customer loads. In some instances, major investments have been deemed imprudent and the utilities have not been allowed to earn a return on some or all of their investment.

Other aspects of regulation pose difficulties for U.S. utilities, particularly in the areas of the environment and of nuclear plant licensing, of the acquisition of rights-of-way for major new transmission lines and of the siting of new generating plants.

As a result of these pressures, U.S. utilities face a period of heightened uncertainty and a proliferation of potential alternative supply options. U.S. investor-owned utilities are therefore looking more and more to purchases from neighbouring U.S. and Canadian utilities as a secure and reliable source of supply to satisfy their customers' needs. While this situation may offer new export opportunities for Canadian utilities, they will have to compete in a rapidly changing market.

5.2.2 Projected Exports of Electricity

Although the bulk of current electricity exports are interruptible, the most notable feature of our export projections is the shift in emphasis by exporters to firm contracts. Interruptible sales of surplus energy are discussed in Section 5.4 while the firm exports which affect the development plans, are discussed below.

For firm electricity exports, we have made the same assumptions in both the low and high cases. Canadian exporters, particularly hydroelectric utilities, are able to provide capacity at prices well below the least cost alternatives in the U.S. market and this competitive advantage is likely to exist in both cases. Moreover, despite the projected increase in firm exports, Canadian power will continue to provide only a small portion of the requirements for incremental capacity in the U.S. For these reasons, our firm export assumptions are relatively insensitive to the variations in demand and in the economic conditions which we project for our two cases. Several provinces are actively pursuing major new sales which we have not included in our projections. These are considered in an alternative case, discussed in Section 5.6.

Our export projections for each exporting province are outlined in more detail below.

New Brunswick

New Brunswick and New England have a long history of mutually advantageous trade. While the size of interconnections is limited, the trade has evolved through joint construction of large plants enabling the region's utilities, including New Brunswick, to avail themselves of economies of scale, to share reserves, to make economy transactions[1] and to realize other interconnection benefits.

Since the early 1970s, New Brunswick has had access to substantial quantities of surplus hydroelectricity from Quebec. This supply has enabled New Brunswick, through special contractual arrangements with Quebec, to sell some of this energy, along with its own oil-fired and nuclear generation, to the export market. New Brunswick has also sold part of the Point Lepreau nuclear plant's production on a unit participation basis. As a result, trade has increased substantially, firm sales of nuclear capacity and energy and an active trade in interruptible energy have reduced New England's dependence on oil-fired generation as well as displacing some coal.

Although the competition for the New England market has increased, New Brunswick may well be able to export additional fossil fuel-based capacity and energy in the 1990s, particularly to northeastern New England.

1. Energy sold by one power system to another to effect a saving in the cost of generation when the receiving party has adequate capability to supply the loads on its own system.

We are assuming that New Brunswick will not renegotiate the existing Point Lepreau I export contracts and will repatriate the capacity and energy in the 1991 to 1994 period for domestic requirements, as the contracts expire. After that, New Brunswick could opt to build additional nuclear or coal units. We have assumed that, for system planning and economic reasons, New Brunswick will choose to build a conventional 400 megawatt coal-fired plant in 1993, half the capacity of which will be sold to the export market. We assume it will be built as a joint project with client utilities in New England; the utilities in the region have often adopted a joint venture approach to building larger, more efficient plants than might otherwise be viable on individual small systems. As a result, we project total firm exports of approximately 200 megawatts by the end of the review period.

Quebec

As a result of an aggressive construction program begun in the 1960s to serve its anticipated domestic loads, Quebec found itself, like other utilities, with a substantial excess supply of capacity and energy by the late 1970s when the expected loads failed to materialize. With a limited ability to either sell surplus energy in-province or transmit it to other utilities[1] at that time, Quebec spilled large quantities of impounded water during that period without producing energy.

This situation prompted Quebec to discount bulk sales to certain domestic industrial users in order to promote higher domestic energy use and to embark on the construction and upgrading of several major interconnections with Ontario, New Brunswick, New York and New England. The technical problems of interconnection have been partially resolved through the use of high-voltage direct-current transmission lines.[2] These measures have met with a large degree of success.

Quebec is now aggressively marketing long-term firm sales to its neighbours and is willing to pre-build new plants for that purpose.

Throughout the 1970s and into the early 1980s, Quebec used its interconnections to export interruptible energy to the U.S. and neighbouring Canadian markets, where it was used mainly to displace generation from more expensive oil and coal.

The demand in the U.S. for more of Quebec's surplus hydro energy than could be delivered using the existing interconnections meant that new lines had to be built. As a result, contracts were concluded with New England and New York for scheduled deliveries of firmer energy, and this provided a financial basis for investments in major new interconnections.

In the last few years, both New England and New York have been actively looking for new sources of supply. Consequently, Quebec's exports are increasingly of long-term firm power and energy, designed to allow the U.S. utilities to defer construction of new plants and to reduce the need for fossil fuel.

Quebec has recently announced that it has concluded export agreements with New York and New England totalling about 2100 megawatts with deliveries to start in the mid-1990s and end well after the end of our study period.

Consistent with its published marketing plan[3] and recent announcements to the press, we are assuming that Quebec will make firm exports additional to those currently licensed, of about 3100 megawatts by the year 2000. The following major exports are included in our projections:

- Two blocks, of 500 megawatts each, to New York State, beginning in 1995;
- An increasing amount of capacity and energy to Maine, starting with 100 megawatts in 1992 and increasing to 600 megawatts in the year 2000;
- 500 megawatts to Vermont, beginning in 1995;
- An additional firm export, as yet unspecified, of 1000 megawatts beginning in the year 2000.

Interruptible energy exports decline in importance in the early 1990s although the decline is more rapid in the high case as existing surpluses are absorbed more quickly by a higher domestic demand growth.

While Quebec has the potential to export much more than the levels we have assumed, we project exports of 3100 megawatts by the year 2000 because of constraints imposed by the market conditions earlier described, and because of technical limitations in transmitting electricity to U.S. markets. In the alternative case described in Section 5.6, we have assumed that

1. For technical reasons Quebec cannot operate its system synchronously with neighbouring ones; it is thus operated in isolation.
2. High-Voltage Direct-Current interconnections allow two systems to exchange energy even though the systems are not synchronized.
3. *Hydro-Québec Development Plan 1988-1990, Horizon 1997*, March, 1988.

these transmission limitations would be overcome.

Ontario

Ontario was, until very recently, Canada's largest exporter of electricity. Its trade continues to be primarily in interruptible energy based on close coordination of exchanges with U.S. utilities. Much of the exported energy is coal-based and is used to substitute for more expensive electricity produced from oil and coal in the market area. Falling oil prices and depressed coal prices have greatly reduced the margin within which these transactions take place. As a result, Ontario's trade advantage has declined and so have its sales. This situation should continue as long as coal and oil prices remain low and there is surplus coal-fired generating capacity in the U.S. market. A short-term increase in nuclear-based exports is projected in the early 1990s when Darlington comes into service and before domestic loads are high enough to absorb its production.

Although most of Ontario's exportable surplus energy is coal-based, its extensive reliance on nuclear generation and access to indigenous and purchased hydroelectricity give it operational flexibility. Through close coordination with neighbouring U.S. utilities, Ontario can tailor its exports to cover a wide range of individual market requirements selling a spectrum of services including firm capacity and energy for short or long periods.

We have assumed that Ontario will not conclude major new export contracts. Although the United States market may offer renewed opportunities for exports in the mid-to-late 1990s, Ontario will not at that time have substantial surpluses of capacity. However, its diversity of supply, its large size and its close co-ordination with U.S. utilities confer upon Ontario advantages in securing continued markets for economy transactions.

Manitoba and Saskatchewan

Saskatchewan exports small amounts of energy to North Dakota; this is expected to continue.

Since the early 1970s, Manitoba has been exporting substantial amounts of hydroelectricity from its abundant hydroelectric resources. Manitoba has substantial undeveloped hydroelectric potential which it would like to develop for sale to the U.S. and to neighbouring Canadian utilities.

Although Manitoba has faced strong competitive pressures in its export markets, it has been successful in negotiating a long-term firm export to Minnesota and is pursuing other potential sales.

Manitoba has advanced the completion of the 1200 megawatt Limestone plant to 1991 to supply a contract for a 500 megawatt firm export. This export is to a Minnesota utility and is scheduled to begin in 1991 and end in 2005. Manitoba has been conducting negotiations with the U.S. for additional exports of firm electricity but these have not resulted in new export contracts as quickly as Manitoba expected. Accordingly, we have assumed that Manitoba will not begin another 550 megawatt firm export until the year 2000. By that time, we expect that the current surplus in the U.S. market area will have been absorbed and that new export opportunities will arise for Manitoba.

The more southern of Manitoba's markets are summer peaking systems, unlike that of Manitoba, which is winter peaking. This diversity of capacity requirements provides ongoing opportunities for seasonal transactions; Manitoba recently announced a seasonal export agreement which will provide it with 200 megawatts of additional winter peaking capacity starting in the mid-1990s in return for providing its U.S. partners with a similar service in the summer season.

We expect that as Manitoba's current surpluses decline, interruptible exports will become less important.

Alberta and British Columbia

While Alberta is not a direct exporter of electricity at present, it has been co-ordinating its coal-based generation more closely with the hydroelectric resources of British Columbia. Since 1986, through an interconnection with Alberta, British Columbia has had access to Alberta's coal-based generating resources. The combination of hydro and coal generation permits British Columbia to better capitalize on export opportunities.

British Columbia has a large surplus hydroelectric capacity although its energy producing capability is variable; because of limited reservoir storage capacity it is very dependent on precipitation. While at peak times Alberta needs most of its capacity, at other times it has excess reliable coal-based energy capability. For British Columbia, Alberta is therefore an ideal complement to the seasonal and annual variability of its hydroelectric system.

Alberta is increasingly interested in finding new markets for its coal-based electricity. The potential exists for future expanded trade with the U.S., either in cooperation with British Columbia or alone through new interconnections.

We have assumed that about 2000 gigawatt hours of energy will be available to British Columbia from Alberta's coal-fired plants annually, throughout the study period. This energy will be partially used in British Columbia and partially exported. We have not included any firm export sales from Alberta in our projections.

British Columbia recently announced its intention to create an export agency to market electricity in the United States. The agency would act as the single source in marketing firm power and energy produced by public or privately owned companies in British Columbia. The agency may also market coal-generated electricity which Alberta could supply.

We have assumed that British Columbia would make a total of about 900 megawatts of firm exports to utilities in the U.S. northwest beginning in the mid-1990s. To serve this market British Columbia envisages the construction of a 400 megawatt hydro unit at an existing plant and the construction of a 600 megawatt coal-fired plant dedicated to the export market. Based on our understanding of the current policy direction taken by British Columbia, this coal-fired plant would be a private sector venture. We have not included in our projections a major firm sale to California but such an export is included in our alternative case described in Section 5.6.

Interruptible energy sales, based on incidental surpluses, are likely to diminish by the early 1990s. However, because of annual variations in precipitation and British Columbia's access to coal-based energy from Alberta, we expect that interruptible sales will continue at a reduced level.

5.3 Generating Capacity and Electrical Energy Production by Region

Electricity demand changes continually, following patterns which recur daily, weekly, seasonally and annually. In Canada, the annual peak demand usually occurs in December or January. Electricity producers require sufficient generating capacity to meet this peak demand. Sound engineering practice also requires that utilities maintain enough reserve generating capacity in order to provide for reliable and continuous service to customers even during equipment breakdowns or maintenance. Some utilities require a larger reserve margin than others, depending on individual equipment characteristics and operating conditions.

Electricity generating units[1] vary in design and in the resource they exploit; specific units are used for different demand-meeting purposes. Larger, newer facilities using more abundant and economical energy resources such as coal and hydro are used as much as possible. These so-called "base-load" units often operate in excess of 80 percent of the time and are characterized by high initial capital costs and low operating costs. At the other extreme are facilities called "peaking" units which operate for very short periods - often less than 5 percent of the time. These are typically older or smaller units which consume premium fuels or are hydro units which have limited reservoir storage capacity. Fossil fuel-fired peaking units are generally less expensive to build for the same capacity than base-load units, but are more expensive to operate.

Some electricity is produced in industries which use by-products of their production processes as fuels to provide thermal energy for industrial processes and to "co-generate" electricity. Some of this co-generated electricity is sold to utilities. Companies and individuals are increasingly interested in producing electricity for their own use and for sale to utilities. Such projects include small hydro sites, municipal refuse disposal and various industrial processes as well as the whole range of renewable technologies such as wind and solar.

In 1986, non-utility generation accounted for 37.9 terawatt hours, about 8 percent of the total electricity production in Canada. By 2005, we project that about 61 terawatt hours, about 10 percent of the total, will come from non-utility sources.

Provincial Projections

To produce electricity, each province exploits those resources which are the most economical to it. Alberta, Saskatchewan and Nova Scotia, for example, base their electricity production on plentiful coal reserves while British Columbia, Manitoba and Quebec rely almost exclusively on abundant hydro resources. The other regions of Canada rely to varying degrees on a mix of indigenous

1. The units are rated by the amount of electricity they can produce per unit of time. For example, a 100 megawatt unit can produce 100 megawatt hours of electricity per hour of operation.

and purchased energy sources. For this reason, each province and territory is dealt with separately in this section in which we describe the resources that we project will be used to meet in-province demands and interprovincial and export sales.

Table 5-2 shows the relative magnitude of the various provinces' generating capacity and actual energy generation for the year 1986, the latest year for which complete statistics have been compiled. The Newfoundland and Labrador statistics include existing long-term firm sales to Quebec from the Churchill Falls generating plant.

Tables 5-3 through 5-14 provide our projections of capacity and production by province and territory. More detailed information can be found in Appendix Tables A5-1 and A5-2. In all of these tables, the numbers shown in the rows entitled "Remaining Capacity" are the arithmetic difference between the total generating capacity and the system peak demand which is here defined as the sum of non-coincident peak loads. This difference includes the surpluses which may be available for sale out-of-province, all required reserves, and any capacity credits attributed to interconnections.

Newfoundland and Labrador

In Newfoundland and Labrador, we project that the load will grow from a level of 9.8 terawatt hours in 1986 to 13.2 and 20.7 terawatt hours in 2005 for the low and high cases respectively. This corresponds to annual growth rates of 1.6 and 4.0 percent.

The Newfoundland and Labrador system is physically divided, with over 95 percent of the load concentrated on the island and most of the major hydro resources located in Labrador.

While the Labrador load is small, less than 5 percent of the total provincial load, there is a 5200 megawatt hydro plant at Churchill Falls. Most of its output is sold to Quebec under a long-term contract. We assume that part of the output of Churchill Falls will continue to meet Labrador loads.

On the island, most of the hydro sites which can be economically developed have been built. The island system has therefore become increasingly reliant on its oil generation; oil-fired capacity supplied about 14 percent of the in-province electrical energy demand in 1986.

As loads increase, new generating capacity is likely to be required around 1990. Consistent with the province's published intentions, we assume that in the long term, the island system will be supplied primarily from Labrador via a submarine cable link. Given the large investments that this project would entail and the considerable lead time required for approvals, design, and construction, we have assumed that the cable to Labrador would not be completed until the year 2000. This would be linked to the construction of the Gull Island hydro project and a recall of some of the Churchill Falls output in accordance with the sale contract with Quebec. In the interim, increases in island loads are assumed to be met by oil-fired units and by burning increasing amounts of fuel oil at Holyrood, the existing oil-fired plant.

Table 5-2

Generating Capacity and Energy Production by Province and Territory -1986

	Capacity [a]		Energy	
	Megawatts	Percent	Gigawatt Hours	Percent
Newfoundland	7123	7.7	40530	8.9
Prince Edward Island	123	0.1	12	0.0
Nova Scotia	2173	2.3	7410	1.6
New Brunswick	3377	3.6	12222	2.7
Quebec	27070	29.2	148926	32.6
Ontario	25678	27.7	125267	27.4
Manitoba	4049	4.4	24059	5.3
Saskatchewan	2747	3.0	11899	2.6
Alberta	7602	8.2	34857	7.6
British Columbia	12579	13.6	50861	11.1
Yukon	122	0.1	344	0.1
Northwest Territories	184	0.2	618	0.1
Total Canada	**92827**	**100.0**	**457005**	**100.0**

Notes: The numbers in this table have been rounded.
[a] The capacity figures exclude purchases.

Source: Appendix Tables A5-1 and A5-2.

Table 5-3

Supply and Demand of Electricity in Newfoundland and Labrador

	1986	1990 Low Case	1990 High Case	2005 Low Case	2005 High Case
Generating Capacity (MW)	7123	7176	7236	7375	10143
Domestic Peak Demand	1820	1893	2197	2375	3625
System Peak Demand	6520	6593	6897	6775	8025
Remaining Capacity	603	583	339	600	2118
Percent of Domestic Peak[a]	33	31	15	25	58
Energy Production (GW.h)	40530	42036	43686	42609	52976
Hydro	39154	41145	41145	41145	52445
Coal	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	1376	891	2541	1464	531
Domestic Consumption (GW.h)	**9834**	**10335**	**12096**	**13238**	**20688**
Net Interprov. Transfers out (in)	**30696**	**31701**	**31590**	**29371**	**32288**
Net Exports	**0**	**0**	**0**	**0**	**0**

Notes: Numbers in this table have been rounded.
[a] Remaining Capacity is expressed as a percentage of domestic peak for Newfoundland and Labrador rather than of system peak.

Table 5-4

Supply and Demand of Electricity in Prince Edward Island

	1986	1990 Low Case	1990 High Case	2005 Low Case	2005 High Case
Generating Capacity (MW)[a]	143	168	168	208	208
Domestic Peak Demand	109	131	131	172	178
System Peak Demand	109	131	131	172	178
Remaining Capacity	34	37	37	36	30
Percent of System Peak	31	28	28	21	17
Energy Production (GW.h)	12	64	65	64	68
Hydro	0	0	0	0	0
Coal	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	12	64	65	64	68
Domestic Consumption (GW.h)	**607**	**709**	**710**	**932**	**966**
Net Interprov. Transfers out (in)	**(595)**	**(645)**	**(645)**	**(868)**	**(898)**
Net Exports	**0**	**0**	**0**	**0**	**0**

Notes: Numbers in this table have been rounded.
[a] Takes into account capacity purchased from New Brunswick of 20 megawatts in 1986, 35 megawatts in 1990, and 80 megawatts in 2005.

In the event that the cable project were deferred or abandoned, Newfoundland would have to adopt an alternative scenario for supplying its island needs. Under these circumstances Newfound–land would likely serve its increasing loads more economically by building additional base load plants burning coal or oil or possibly by building a nuclear plant.

In Newfoundland, non-utility producers generated about 450 gigawatt hours in 1986, about 4.5 percent of the provincial load; most of this was produced in hydro plants. We do not expect this percentage to increase rapidly over the study period. By 2005 we expect non-utility generation to account for about 620 gigawatt hours, 4.7 and 3.0 percent of in-province demand in the low and high cases respectively. The increase is assumed to come from an intensified use of wood-wastes in the forest products industry.

Prince Edward Island

The demand projections for Prince Edward Island are very similar for both price cases, starting at 607 gigawatt hours in 1986 and growing to about 950 gigawatt hours in 2005, an annual growth rate of about 2.4 percent.

Although Prince Edward Island has sufficient oil-fired generating capacity to satisfy its own needs at present, for economic reasons it has been obtaining almost all of its electricity from New Brunswick via a submarine cable interconnection. We assume that this interconnection will be upgraded so that the full 200 megawatt capacity of the submarine cable will be available for use.

Table 5-5

Supply and Demand of Electricity in Nova Scotia

	1986	1990		2005	
		Low Case	High Case	Low Case	High Case
Generating Capacity (MW)	2173	2180	2180	2670	2820
Domestic Peak Demand	1469	1650	1663	2127	2341
System Peak Demand	1469	1650	1663	2127	2341
Remaining Capacity	704	530	517	543	479
Percent of Domestic Peak	48	32	31	26	20
Energy Production (GW.h)	7410	8455	8525	11704	12889
Hydro	1039	1102	1102	1102	1102
Coal	5402	6173	6199	8796	10396
Nuclear	0	0	0	0	0
Other	969	1180	1224	1806	1391
Domestic Consumption (GW.h)	**7950**	**9015**	**9085**	**11604**	**12789**
Net Interprov. Transfers out (in)	**(540)**	**(560)**	**(560)**	**100**	**100**
Net Exports	**0**	**0**	**0**	**0**	**0**

Note: Numbers in this table have been rounded.

Prince Edward Island has passed legislation which encourages the province's utility to purchase electricity from on-island independent producers. None the less we do not expect large non-utility supplies during the study period. Accordingly, we expect that New Brunswick will continue to supply virtually all of the energy and all of the additional capacity needs of Prince Edward Island.

Nova Scotia

In 1986, the provincial demand for electricity in Nova Scotia was 8.0 terawatt hours. We anticipate that this will grow to 11.6 and 12.8 terawatt hours by 2005 for the low and high cases respectively. This corresponds to annual load growth rates of 2.0 and 2.5 percent.

The province's generating capacity mix is currently about 42 percent oil, 40 percent coal and 18 percent hydro.

With the completion of the conversion of the Point Tupper No. 2 generating station from oil to coal, Nova Scotia has completed its conversion of major oil-fired plants to coal. We are assuming that all new large base-load capacity additions will burn Nova Scotia coal. This reflects the provincial policy of developing its indigenous coal resources.

There is a 20 megawatt tidal power plant in operation at Annapolis Royal but, because of the relatively high cost of tidal units, we assume no further development of tidal power within the study period.

The next major addition to be completed is the 150 megawatt coal-fired unit at Trenton in 1991. We project that additional generating plants will be required by the mid-1990s. These are assumed to be 150 megawatt conventional coal-fired units; additions later in the study period may be 150 megawatt fluidized bed combustion units.

Nova Scotia's non-utility electricity producers generated 360 gigawatt hours in 1986, about 5 percent of the provincial total. Most of this electricity was produced by the forest products industry. We anticipate that non-utility generation will increase by about 30 megawatts in 1993 as a result of the government's policy of calling for proposals from private power producers. Thereafter, the rate of increase will diminish, although the proportion of wood-wastes being burned should increase. By 2005, non-utility production is estimated at about 570 gigawatt hours, 4.5 percent of total production.

Nova Scotia and New Brunswick have traded electricity on an interruptible basis for some time. On average, Nova Scotia buys more than it sells to New Brunswick. Most of the trade is in economy energy. We assume that these transactions will continue at a level consistent with recent past practice. While future sales to New Brunswick of firm coal-fired capacity are possible, we have not included them in our assumptions.

New Brunswick

We project that by 2005 in-province demand in New Brunswick will grow to about 18.2 terawatt hours in the low case and to 19.9 terawatt hours in the high from the 1986 level of 11.6 terawatt hours. This translates into average annual load growth rates of about 2.4 percent and 2.9 percent respectively.

The province currently has a mix of about 45 percent oil, 27 percent hydro, 19 percent nuclear[1] and 9 percent coal capacity.

Non-utility producers generated 771 gigawatt hours in 1986, about 6 percent of the provincial demand. Most of this was produced at hydro plants owned by forest products companies. We expect that private electricity generation will increase modestly in the study period, primarily reflecting the more intense use of wood waste. By 2005, we project non-utility production to total 1.1 terawatt hours or about 5 percent of total production.

New Brunswick has a 1000 MW oil-fired plant at Coleson Cove which we expect will be used more intensively to meet domestic needs as these grow. The oil prices underlying our high and low cases are not high enough to discourage the use of this facility, nor to justify its conversion to other fuels. A conversion of Coleson Cove to an emulsion of water and bitumen imported from Venezuela might be economic in the mid-to-late 1990s but we have not included this possibility in our assumptions. New Brunswick is currently investigating the use of this new fuel as an alternative to burning heavy oil or converting to coal. We anticipate that further major capacity additions will be coal-based, starting with an additional 400 megawatt unit in the early 1990s (half of the output of this plant is assumed to be exported on a firm basis). Thereafter, we expect that New Brunswick will add coal-fired units of 200 megawatts using fluidized bed technology.

A major source of electricity for New Brunswick is Quebec with which it shares a total of about 1000 megawatts of interconnection capacity. New Brunswick uses this mainly to make interruptible energy purchases. In 1986, purchases from Quebec were equivalent to about one-half of New Brunswick's electrical energy demand. Most of the purchased energy is used to displace fossil fuels in New Brunswick; but in cooperation with Quebec, some of this purchased energy, along with some of New Brunswick's own surplus fossil-fuel and hydro-generated energy, is sold on an interruptible basis to Nova Scotia, Prince Edward Island and New England. Interruptible purchases from Quebec are not expected to continue after the mid-1990s. This is because of the lower levels of expected hydro surpluses on the Quebec system as well as Quebec's expanded access to more remunerative markets in the U.S., where the cost of alternative sources is higher than in New Brunswick. It is likely that New Brunswick will continue making interruptible energy sales to Nova Scotia and Prince Edward Island.

We also expect that New Brunswick will sell small blocks of firm capacity and energy from specific plants to Prince Edward Island, as loads grow in that province.

New Brunswick has recently concluded a firm purchase agreement with Quebec for varying amounts of capacity and energy ranging up to 675 megawatts beginning in 1988 and ending in 1994. We have not included any other firm purchases from Quebec in our study, although one is included in our alternative case described in Section 5.6.

New Brunswick's only nuclear plant (Point Lepreau I) is a 630 megawatt

Table 5-6

Supply and Demand of Electricity in New Brunswick

	1986	1990		2005	
		Low Case	High Case	Low Case	High Case
Generating Capacity (MW)	3377	4072	4072	4359	4559
Domestic Peak Demand	2199	2556	2582	3147	3440
System Peak Demand	2601	2973	2999	3499	3792
Remaining Capacity	776	1099	1073	860	767
Percent of System Peak	30	37	36	25	20
Energy Production (GW.h)	12222	12823	12769	21084	22809
Hydro	3185	2771	2771	2771	2771
Coal	945	2137	2137	6341	7743
Nuclear	5227	4857	4857	4857	4857
Other	2865	3058	3004	7115	7438
Domestic Consumption (GW.h)	**11555**	**14094**	**14240**	**18154**	**19899**
Net Interprov. Transfers out (in)	**(5925)**	**(7795)**	**(7995)**	**768**	**(52)**
Net Exports	**6592**	**6524**	**6524**	**2162**	**2962**

Note: Numbers in this table have been rounded.

1. This is the 630 megawatt Point Lepreau nuclear unit and includes a portion exported to New England until the early 1990s.

unit. About 230 megawatts of its capacity is dedicated to firm exports until the early 1990s. Although New Brunswick could opt to build a second nuclear unit at Point Lepreau, it has been reluctant to do so because of the large up-front financial risks and burdens this involves for itself and for potential joint ventures partners in the U.S. For this reason we have not included it in our study.

Quebec

In 1986, the in-province load was 153 terawatt hours, of which about 20 percent was purchased energy generated at Churchill Falls in Labrador. The load is projected to grow to 203 and 224 terawatt hours in 2005 in the low and high cases respectively. The corresponding annual load growth rates are 1.5 and 2.0 percent. Quebec's own generating capacity mix is currently about 94 percent hydro, 4 percent oil and 2 percent nuclear.

Hydro-Québec in its recently published development plan,[1] outlined its strategy for managing demand by developing a base of up to 2000 megawatts of interruptible industrial loads by about 1993. As well, Quebec plans to further reduce its peak load in 1990 by 3000 megawatts by promoting the use of dual-energy systems. Customers will be provided with rate incentives to use electricity in off-peak hours and to rely on oil during peak hours. Combined, we expect these strategies to reduce the annual peak load below what it would otherwise be by about 5000 megawatts by the mid-1990s.

In Quebec, non-utility producers generated 17.8 terawatt hours in 1986, about 12 percent of the provincial demand. Most of this was hydro production by the aluminium industry. There is also a small potential for private power production – small-hydro, co-generation, and municipal refuse incineration, – but given the uncertainties surrounding these projects, we do not expect much expansion of non-utility production in Quebec. By 2005, we expect that non-utility production will be about 20 terawatt hours, about 9.5 percent of total production.

Quebec has a large reservoir storage capacity and is able to regulate its hydroelectric production to even out fluctuations in seasonal and annual rainfall. This enables Quebec to supply its own loads while providing it with substantial operational flexibility to make out-of-province sales at times when market prices are most attractive, thereby maximizing the value of this energy for Quebec.

Quebec would not require major additional capacity until the mid-1990s (other than peaking additions at the Manic 5 and La Grande 2 generating stations) if it had to satisfy only the growing in-province and existing extraprovincial contractual demands. After 1995, additional peaking and base load hydro units could be built as needed.

In addition to meeting provincial loads and existing contracts, we assume that Quebec will advance the construction of major hydro projects in order to make about 3100 megawatts of additional firm export sales (see Section 5.2.2). We also expect that Quebec will build additional transmission lines and proceed with a major upgrad-

Table 5-7

Supply and Demand of Electricity in Quebec

	1986	1990 Low Case	1990 High Case	2005 Low Case	2005 High Case
Generating Capacity (MW)	31770	33065	33065	42143	46746
Domestic Peak Demand	27274	27256	27992	35388	39246
System Peak Demand	27511	28318	29054	38574	42432
Remaining Capacity	4259	4747	4011	3569	4314
Percent of Domestic Peak[a]	15	17	14	9	10
Energy Production (GW.h)	148926	159315	161322	198895	220581
Hydro[a]	144901	153874	155881	191467	213743
Coal	0	0	0	0	0
Nuclear	3792	5101	5101	5101	5101
Other	233	340	340	2327	1737
Domestic Consumption (GW.h)	**152626**	**158402**	**162398**	**202934**	**223917**
Net Interprov. Transfers out (in)	**(16329)**	**(17778)**	**(19767)**	**(28448)**	**(30515)**
Net Exports	**12629**	**18691**	**18691**	**24409**	**27179**

Notes: Numbers in this table have been rounded.
[a] Takes into account capacity purchased from Churchill Falls of 4750 megawatts in 1986, 4750 megawatts in 1990, and 4750 megawatts in 2005.

1. *Hydro-Québec Development Plan 1988-1990, Horizon 1997*, March, 1988.

ing of the Quebec transmission system to bring the reliability of the Quebec network in line with the criteria of the North American Electric Reliability Council.

In Canada, Quebec has major interconnections with Newfoundland and Labrador, New Brunswick and Ontario. We assume that purchases from Churchill Falls in Labrador will continue as contracted. Sales to New Brunswick have almost always been at a level close to the physical limit of the interconnections. We expect that this will continue until the early 1990s. Thereafter, the sales will vary depending on the amount of surplus energy available in Quebec. As mentioned above, we are including a firm sales agreement with New Brunswick for varying amounts of capacity and energy over a period beginning in 1988 and ending in 1994.

We anticipate that sales of interruptible energy to Ontario will largely disappear by the mid-1990s as Quebec's surpluses diminish and Ontario's Darlington nuclear plant comes into service. For Quebec, Ontario is a less lucrative market than the U.S. for economy energy sales because of Ontario's economic nuclear and efficient coal-burning plants. We have not included any major firm sale to Ontario in either our low or high case projections, although one is included in the alternative case, described in Section 5.6.

Ontario

We project that by 2005, the in-province demand for electricity will grow to 171.8 and 184.9 terawatt hours, for the low and high cases respectively, from the 1986 level of 127.2 terawatt hours. This corresponds to annual growth rates of 1.6 and 2.0 percent.

Table 5-8

Supply and Demand of Electricity in Ontario

	1986	1990		2005	
		Low Case	High Case	Low Case	High Case
Generating Capacity (MW)	25734	31297	31297	33779	36526
Domestic Peak Demand	21569	23205	23875	27914	30093
System Peak Demand	22204	23640	24310	27914	30093
Remaining Capacity	3530	7657	6987	5865	6433
Percent of System Peak	16	32	29	21	21
Energy Production (GW.h)	125267	140457	146690	170235	182974
Hydro	41206	39528	39528	42114	42114
Coal	24402	14428	20661	33080	32744
Nuclear	58213	83909	83909	90642	103453
Other	1446	2592	2592	4399	4663
Domestic Consumption (GW.h)	**127031**	**138230**	**142163**	**171778**	**184947**
Net Interprov. Transfers out (in)	**(8027)**	**(5723)**	**(3423)**	**(3123)**	**(3123)**
Net Exports	**6263**	**7950**	**7950**	**1580**	**1150**

Note: Numbers in this table have been rounded.

In 1986, non-utility producers generated 3.8 terawatt hours of electricity, 3 percent of the provincial demand. While most of this was produced in relatively small hydro facilities, a large and growing proportion was generated from fossil and by-product fuels. As part of its supply options review,[1] Ontario has considered the possible contributions of additional non-utility electricity producers. These include industrial co-generators, private power companies and individuals. We assume that these will contribute about 250 additional megawatts of capacity by 2005. By the year 2005, we project that non-utility producers will generate about 6.9 terawatt hours, about 4.0 percent of the total production.

Ontario's mix of generating capacity is currently about 34 percent nuclear, 29 percent coal, 23 percent hydroelectric and 14 percent natural gas, oil and other sources.

Ontario has interconnections with both Manitoba and Quebec, and with New York and Michigan. Its U.S. ties also give it access to markets in other states. In Canada, Ontario purchases mainly interruptible energy from Quebec and Manitoba. We assume that the purchases from Quebec will end in the early 1990s while those from Manitoba will continue, although at lower levels. We also include the recently announced 200 megawatt firm purchase from Manitoba beginning in 1998.

We assume that the four unit Darlington nuclear plant (3500 megawatts in total) will be completed on schedule by 1992. Following Darlington, and within the range of the development

1. *Ontario Hydro, Demand/Supply Options Study - The Options* (Report No. 652SP) and *1987 Bulk Electricity System Demand/Supply Report 1987-2006* (Report No. 661SP).

options currently being considered, we assume that Ontario will opt for a mixed electricity supply strategy:

- Ontario will build and redevelop several small and medium sized hydro facilities and put back into service some of its fossil-fueled units now in storage, notably units 3 and 4 at Lennox.
- A load management and peak load reduction program will be implemented. We expect that Ontario will reduce its demand growth by providing incentives mostly to major customers to reduce their consumption by increasing their efficiency of end use. The savings are projected to be about 2000 megawatts and 12 000 gigawatt hours by 2005.
- Ontario will reduce the peak demand by encouraging customers to shift some of their electricity use to off-peak times, with measures such as the recently announced time of use rates for wholesale customers. We project that this will reduce the system peak demand by about a further 1000 megawatts by the year 2000.
- Ontario will build new nuclear and coal plants, as needed, early in the next century. We assume that Ontario will install flue gas desulphurisation facilities (scrubbers) on several of its major coal-burning units, enabling them to be more intensively used while respecting the more stringent acid gas emission limitations recently imposed by the province.

Ontario has considered purchasing blocks of firm power and energy from Quebec and Manitoba as an alternative to building additional plants. Other than a small purchase from Manitoba these discussions have yet to produce concrete results. Accordingly, we have not included any large purchases from Quebec or Manitoba in our two cases; for a discussion of these possible alternatives see Section 5.6.

Manitoba

In 1986, the in-province demand for electricity in Manitoba was 16.2 terawatt hours. By 2005, the demand is expected to grow to 23.0 and 23.9 terawatt hours for the low and high cases respectively, corresponding to annual load growth rates of about 2 percent.

Manitoba's current generating capacity mix is about 89 percent hydro and 9 percent coal, with the balance being primarily light oil and diesel.

In 1986, non-utility producers generated about 75 gigawatt hours, most of it from hydro plants. This amounts to only about three-tenths of a percent of the provincial demand. Because of the low cost of Manitoba's utility-produced electricity, we do not expect non-utility producers to increase in importance in Manitoba during the study period.

We assume that Manitoba will use its abundant undeveloped hydro resources to meet its projected loads. Without exports, Manitoba would not have to build a major new plant until the mid-1990s although one is now being built, partly for export.

Manitoba is interconnected with Ontario and Saskatchewan but transactions with these provinces have been modest in comparison with exports to the U.S. This results from Saskatchewan's abundant supply of inexpensive lignite coal, and from the limited size and long length of the transmission links between Manitoba and Ontario's eastern system. For

Table 5-9

Supply and Demand of Electricity in Manitoba

	1986	1990		2005	
		Low Case	High Case	Low Case	High Case
Generating Capacity (MW)	4349	4605	4605	6530	6618
Domestic Peak Demand	3082	3277	3312	4320	4492
System Peak Demand	3182	3437	3472	5570	5742
Remaining Capacity	1167	1168	1133	960	876
Percent of Domestic Peak	37	34	33	17	15
Energy Production (GW.h)	24059	21319	21506	34607	34761
Hydro	23840	21239	21338	34522	34676
Coal	95	0	88	0	0
Nuclear	0	0	0	0	0
Other	124	80	80	85	85
Domestic Consumption (GW.h)	**16222**	**17140**	**17327**	**23003**	**23857**
Net Interprov. Transfers out (in)	**859**	**800**	**800**	**2200**	**2200**
Net Exports	**6978**	**3379**	**3379**	**9404**	**8704**

Note: Numbers in this table have been rounded.

these reasons, we assume that, apart from the previously mentioned firm sale to Ontario, transactions with neighbouring provinces will continue at levels similar to those of the recent past.

Saskatchewan

By 2005, we project that in-province electricity demand will grow to 16.8 and 19.1 terawatt hours in the low and high cases respectively, from the 1986 level of 12 terawatt hours. This corresponds to annual growth rates of 1.8 and 2.5 percent respectively.

The province's current mix of generating facilities is about 57 percent coal, 29 percent hydroelectric and 14 percent natural gas, diesel, and light oil. In Saskatchewan, non-utility producers generated about 344 gigawatt hours in 1986, about 3 percent of the provincial total. We have included only a small, gradual increase in this production over the study period and have not included any major new non-utility electricity producers. We project that, by 2005, non-utility producers will supply 455 gigawatt hours, about 2.5 percent of total production.

Saskatchewan is largely self-reliant in capacity and energy. It conducts only modest transactions with Manitoba, purchasing a little more, on average, than it sells. Its trade with the United States and Alberta is also modest. In 1987, Saskatchewan and Alberta completed a new high-voltage direct-current interconnection. The usable capacity of this interconnection is approximately 110 megawatts. It will confer a benefit to Saskatchewan of about 100 megawatts of reserve equivalent and give both utilities the ability to make economy and other transactions.

Since Saskatchewan has a substantial coal resource, we assume that new coal-fired units will be built as needed, similar to the Shand I generating unit scheduled for completion in 1992. As well, we have included two hydro projects in our expansion plan:

- An expansion of the existing 100 megawatt Island Falls plant to 200 megawatts in the late 1990s, and
- A new 300 megawatt plant called Wintego, which we have scheduled in service around the year 2000.

We assume that peaking needs will be met by a combination of out-of-province purchases and gas-burning combustion turbine units. We have not included any allowance for peak demand shifting or demand management in Sask–atchewan.

Table 5-10

Supply and Demand of Electricity in Saskatchewan

	1986	1990 Low Case	1990 High Case	2005 Low Case	2005 High Case
Generating Capacity (MW)	2847	2897	2897	3547	3927
Domestic Peak Demand	2129	2250	2359	2973	3386
System Peak Demand	2139	2260	2369	2983	3396
Remaining Capacity	708	637	528	564	531
Percent of System Peak	33	28	22	19	16
Energy Production (GW.h)	11899	12767	13384	16942	19276
Hydro	3767	3776	3776	5378	5378
Coal	7728	8567	9139	10988	13236
Nuclear	0	0	0	0	0
Other	404	424	469	576	662
Domestic Consumption (GW.h)	**11947**	**12734**	**13351**	**16799**	**19133**
Net Interprov. Transfers out (in)	**(139)**	**(1)**	**(1)**	**(1)**	**(1)**
Net Exports	**91**	**34**	**34**	**144**	**144**

Note: Numbers in this table have been rounded.

Alberta

The 1986 in-province demand for electricity was 34.8 terawatt hours. We project that this will grow to 47.3 and 61.0 terawatt hours in 2005 for the low and high cases respectively. The corresponding annual load growth rates are 1.6 and 3.0 percent.

Alberta's current generating capacity mix is about 64 percent coal, 20 percent gas, 10 percent hydro and 6 percent oil and other.

In 1986, non-utility producers generated 3.2 terawatt hours, about 9 percent of the provincial total. This production was based largely on the use of by-product fuels and natural gas. We assume that by 2005, industrial generation and private producers will have increased their capabilities by about 450 megawatts. By then non-utility producers are projected to generate about 7.1 terawatt hours,

15 and 12 percent of production in the two cases.

Although major electricity export projects are possible, we have not included any in our supply outlooks, as we consider them speculative at this time. Nor have we allowed for any demand management; there is no indication at present that Alberta will institute such a program. We do not assume any shifting of peak demand in the study period; given Alberta's high overall load factor, we see little opportunity to achieve much peak load reduction in this manner.

Alberta's coal resources are plentiful and inexpensive to extract. Accordingly, we have assumed that all new large capacity additions will be coal-fired. The next major scheduled additions are Genesee II in 1989, Sheerness II in 1990 and Genesee I in 1991. Each of these is a coal-fired unit of about 400 megawatts capacity. We assume that new peaking capacity needs will be served using gas-burning combustion turbine units, and by using the interconnection with British Columbia to make purchases. The two provinces' systems, Alberta's thermal and British Columbia's hydraulic, have operating and physical characteristics which are naturally complementary. For example, Alberta may operate its coal-fired generating plants at full load in off-peak hours, selling energy to British Columbia which can then allow water to be stored in its reservoirs. This energy can later be recalled by Alberta to supplement its base load coal-fired plants' generation or, alternatively, be used by British Columbia or exported. We are assuming that the two provinces will coordinate their operations in this manner, will make economy transactions and will share reserves. Alberta is crediting its interconnection with British Columbia with a reserve capacity equivalent of about 300 megawatts.

Table 5-11

Supply and Demand of Electricity in Alberta

	1986	1990 Low Case	1990 High Case	2005 Low Case	2005 High Case
Generating Capacity (MW)	7902	8739	8669	9458	11463
Domestic Peak Demand	5322	5587	6068	7774	9574
System Peak Demand	5322	5587	6068	7774	9574
Remaining Capacity	2580	3152	2601	1684	1889
Percent of Domestic Peak	48	56	43	22	20
Energy Production (GW.h)	34857	35604	39078	49268	62978
Hydro	1816	1636	1636	1636	1636
Coal	28362	29977	32878	39496	52519
Nuclear	0	0	0	0	0
Other	4679	3991	4564	8136	8823
Domestic Consumption (GW.h)	**34800**	**35205**	**38679**	**47269**	**60979**
Net Interprov. Transfers out (in)	**60**	**400**	**400**	**2000**	**2000**
Net Exports	**(3)**	**(1)**	**(1)**	**(1)**	**(1)**

Notes: Numbers in this table have been rounded.

British Columbia

In British Columbia, the 1986 in-province electricity demand was 49.5 terawatt hours. We project that this will grow to 67.3 and 70.7 terawatt hours in 2005 for the low and high cases respectively. This translates into annual growth rates of 1.7 and 1.9 percent.

British Columbia's generating capacity mix is currently about 88 percent hydro, 9 percent natural gas and 3 percent oil and other fuel types.

In 1986, non-utility producers generated 11.2 terawatt hours of electricity, about 22 percent of total in-province demand. Most of this production was generated at hydro plants for use by the aluminium industry. In 2005, non-utility production is projected at about 19 terawatt hours, about 24 percent of total production.

British Columbia has identified the potential for up to 2500 gigawatt hours of additional non-utility generation during the study period, much of it using forest product wastes, but we have not included it in our projections, because British Columbia expected this generation to be attractive only if provincial demand growth were higher than we are projecting in our high case. The only exception to this is the 500 megawatt expansion of the Kemano hydro plant owned by an aluminium producer.

Although British Columbia has a large undeveloped hydroelectric potential, the recently published electricity development plan[1] envisages reliance, in the medium term, on a number of different

1. *B.C. Hydro, Twenty Year Resource Plan*, March, 1988.

sources of supply for domestic needs. British Columbia is expecting that better coordination with the Bonneville Power Administration in the U.S. northwest will result in a more effective use of reservoirs and increase the dependability of production from plants on the Columbia River. This is assumed to add about 1300 gigawatt hours to British Columbia's dependable supply; a similar approach with private hydro producers in-province could add a further 260 gigawatt hours.

The Columbia River Treaty, whereby British Columbia sold to U.S. utilities its share of benefits from the joint developments on the Columbia River, ends in 1998. We assume that British Columbia will repatriate its entitlement in order to serve its in-province needs. This could add about 500 gigawatt hours in 1999, increasing to 4700 gigawatt hours annually by 2004. As mentioned earlier, we expect that British Columbia will purchase surplus coal-fired energy from Alberta.

British Columbia has stated its intent to institute a plan of demand management. We assume that this will result in demand reductions of about 100 gigawatt hours in 1988, increasing gradually to about 3500 gigawatt hours for the high case and 2600 gigawatt hours in the low case by 2005. As well, we assume that some shifting of peak demands to off-peak times will result in reductions of up to 5 percent of the annual peak load by 2005.

Although British Columbia is planning to invite prospective independent producers to submit proposals for future supplies, possibly to exploit the province's coal reserves, we are not including such a project to service domestic needs. We assume that such a private venture, based on a 600 megawatt coal plant, would be built to service the export market, as discussed in Section 5.2.2.

Table 5-12

Supply and Demand of Electricity in British Columbia

	1986	1990		2005	
		Low Case	High Case	Low Case	High Case
Generating Capacity (MW)	12579	12579	12579	15381	16461
Domestic Peak Demand	7830	8103	8162	10411	10978
System Peak Demand	7930	8203	8262	11411	11978
Remaining Capacity	4649	4376	4317	3970	4483
Percent of System Peak	59	53	52	35	37
Energy Production (GW.h)	50861	59022	59080	65915	69418
Hydro	48935	56866	56866	56867	60678
Coal	0	0	0	4205	4205
Nuclear	0	0	0	0	0
Other	1926	2156	2214	4843	4535
Domestic Consumption (GW.h)	49494	51872	52210	67715	71128
Net Interprov. Transfers out (in)	(62)	(400)	(400)	(2000)	(2000)
Net Exports	1429	7550	7270	200	290

Note: Numbers in this table have been rounded.

By using up its current surpluses and with all of these supply options, British Columbia will not require major hydro plant additions until early in the next century. We assume that development of British Columbia's hydro sites would resume at that time with the construction of the 900 megawatt Site C hydro plant to serve domestic needs[1].

Yukon

The Yukon's electrical energy demand in 1986 was 344 gigawatt hours. We expect this to grow to 423 and 479 gigawatt hours in 2005 in the low and high cases respectively. This corresponds to annual growth rates of 1.1 and 1.8 percent in the two cases.

In the Yukon, about 66 percent of the generating capacity is hydroelectric and 34 percent is diesel. Approximately 94 percent of electrical energy generation was from hydro in 1986, and this was concentrated at Whitehorse. Although there may be a role for other small hydro or wind projects, for both cases we assume that future capacity additions in isolated locations will be diesel, with the exception of a 2 megawatt hydro plant in 1994 to serve Dawson. A substantial amount of extra reserve diesel capacity is maintained to provide adequate security of supply to isolated communities during the long winter season.

1. In the October 1986 Report, we had assumed that the Site C project would be built mainly for export. We have changed our assumptions to reflect the changes in British Columbia's export strategy.

Table 5-13

Supply and Demand of Electricity in Yukon

	1986	1990 Low Case	1990 High Case	2005 Low Case	2005 High Case
Generating Capacity (MW)	122	122	122	124	124
Domestic Peak Demand	69	60	69	80	91
System Peak Demand	69	60	69	80	91
Remaining Capacity	53	62	53	44	33
Percent of Domestic Peak	77	103	77	55	36
Energy Production (GW.h)	344	316	363	423	479
Hydro	322	288	328	375	403
Coal	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	22	28	35	48	76
Domestic Consumption (GW.h)	344	316	363	423	479
Net Interprov. Transfers out (in)	0	0	0	0	0
Net Exports	0	0	0	0	0

Notes: Numbers in this table have been rounded.

Table 5-14

Supply and Demand of Electricity in Northwest Territories

	1986	1990 Low Case	1990 High Case	2005 Low Case	2005 High Case
Generating Capacity (MW)	184	184	184	184	198
Domestic Peak Demand	120	122	125	161	172
System Peak Demand	120	122	125	161	172
Remaining Capacity	64	62	59	23	26
Percent of System Peak	53	51	47	14	15
Energy Production (GW.h)	618	632	652	847	906
Hydro	346	307	307	307	307
Coal	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	272	325	345	540	599
Domestic Consumption (GW.h)	618	632	652	847	906
Net Interprov. Transfers out (in)	0	0	0	0	0
Net Exports	0	0	0	0	0

Note: Numbers in this table have been rounded.

Northwest Territories

In 1986, the Northwest Territories' electricity demand was 618 gigawatt hours. We anticipate that this will grow to about 847 and 906 gigawatt hours in 2005 in the low and high cases respectively, corresponding to annual growth rates of 1.7 and 2.0 percent in each case.

Non-utility producers generated about 110 gigawatt hours or about 18 percent of the territorial consumption in 1986. We assume that no new non-utility plants will be built in the study period. We project that non-utility production will increase to only 114 gigawatt hours or about 13 percent of total production by 2005.

While the Northwest Territories' generating capacity is made up of about 77 percent diesel units and 23 percent hydro, electricity generation in 1986 was about 56 percent hydro. The reason for this seeming imbalance is that, as in the Yukon, much of the hydro generation is concentrated near the capital, the rest of the territory being dependent mainly on oil. We assume that all new capacity additions will be diesel although there may be a role for small hydro and wind projects, as in the Yukon.

5.4 Extraprovincial Trade

Exports

As discussed in Section 5.2 we project that firm exports will grow in importance throughout the study period. By 2005 we expect that the marketing efforts of New Brunswick, Quebec Manitoba and British Columbia will have resulted in about 5500 megawatts and 31.0 terawatt hours of firm exports.

Interruptible exports of surplus energy will continue over the entire study period, although at lower than current levels. Excess energy capability is an inherent characteristic of electric power systems, be they hydro, thermal or a mixture of both modes of generation.

In a hydro system, capacity additions are based on dependable river flow conditions while actual production will vary with actual river flows which are, on average, greater.

In a thermal system, the availability of fossil fuel-fired plants is usually greater than the load factor of the system. As a result, these plants are available to produce surplus electricity for sale if there are economic benefits for seller and buyer.

Interconnections between utility systems allow utilities to coordinate the operations of their systems in order to maximize the economic benefits that they bring. For example coordinated operations:

- allow economy energy sales to take place, which ensures that the least cost increment of production is used to meet each increment of load. The resulting savings from such operations are shared equitably between the parties.

- permit a practice called "energy banking", the time-shifting of economical energy production by using a neighbouring utility's hydro storage; and

- provide emergency support of neighbouring systems when these suffer unplanned outages of plants or unexpectedly high peaks in demand.

A review of the Canada - U.S. trade in interruptible energy in the past shows that the Canadian utilities whose generation is predominantly hydro, coal or nuclear have production costs significantly lower than those of neighbouring U.S. utilities. Energy flows have therefore tended to be on balance from Canada into the U.S.

The large volume of current interruptible exports is the result of efforts by utilities to dispose of temporary surpluses which occurred when actual Canadian electricity demand grew at lower rates than had been expected. By the early 1990s existing surpluses will have been largely absorbed by

Figure 5-3
Net Electricity Exports by Type

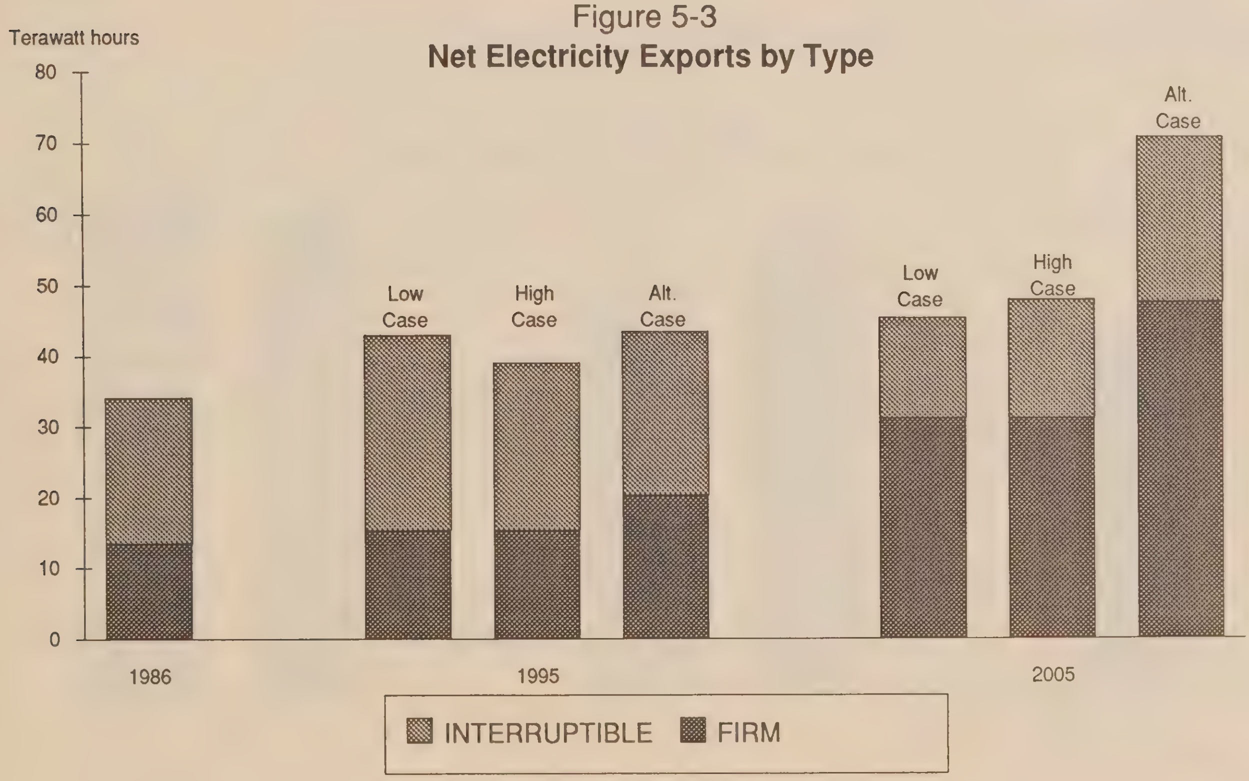


Table 5-15

Net Electricity Exports by Province

(Terawatt hours)

	1986	1990 Low Case	1990 High Case	1990 Alt. Case	2005 Low Case	2005 High Case	2005 Alt. Case
New Brunswick	6.7	6.5	6.5	6.5	2.2	3.0	10.5
Quebec	12.6	18.6	18.7	18.7	24.4	27.1	33.0
Ontario	6.2	8.0	8.0	8.0	1.6	1.2	1.6
Manitoba	7.0	3.4	3.4	3.4	9.4	8.7	13.0
Saskatchewan	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Alberta	0.0	0.0	0.0	0.0	0.0	0.0	0.0
British Columbia	1.4	7.6	7.3	7.3	7.6	7.7	12.6
Canada Total	**34.0**	**44.2**	**44.0**	**44.0**	**45.3**	**47.8**	**70.8**

Note: Numbers in this table have been rounded.

Source: Appendix Table A5-2.

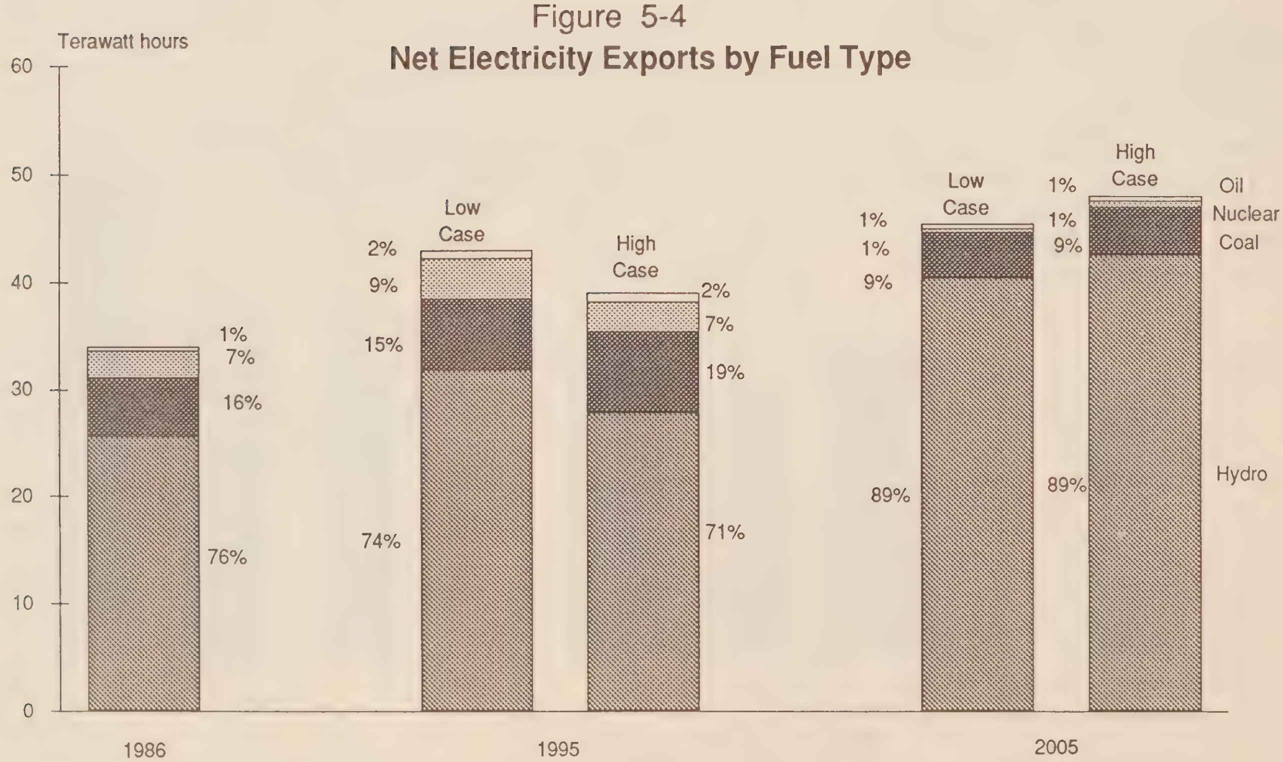
the increases in Canadian loads. Interruptible exports, which in 1986 were about 24 terawatt hours (71 percent of total exports), are expected to decrease to about 16 terawatt hours in 2005, about 33 percent of the total.

Total net exports, which were about 34 terawatt hours in 1986 and 44 terawatt hours in 1987, will decline somewhat and then return to a level of 44 terawatt hours by 1990. After that, exports continue at a level of 45 to 48 terawatt hours in both cases, as shown in Figure 5-3 and Table 5-15.

Electricity for export is likely to continue to be produced mainly by hydro and coal-burning plants.

Figure 5-4

Net Electricity Exports by Fuel Type



Source: Appendix Table A5-6

There is little difference in our export projections between the low and high cases. This results from the complex interrelationship between economic growth, electricity prices, market demand and the characteristics of the industry.

The difference in total net export projections between the two cases arises from our projections of interruptible exports. In the high case, as a result of the projected higher demand for electricity in Canada, linked to a more buoyant economy, we expect that existing electricity surpluses would be more rapidly absorbed leaving less for the interruptible export market. The opposite is true in the low case where we anticipate that existing surpluses would persist longer into the early 1990s leading to a slower decline in interruptible exports.

Interprovincial Transactions

Our projections of interprovincial transactions are summarized for 1986 and 2005 in Figure 5-5.

As described in Section 5.3, we have included only a few firm transactions between provinces:

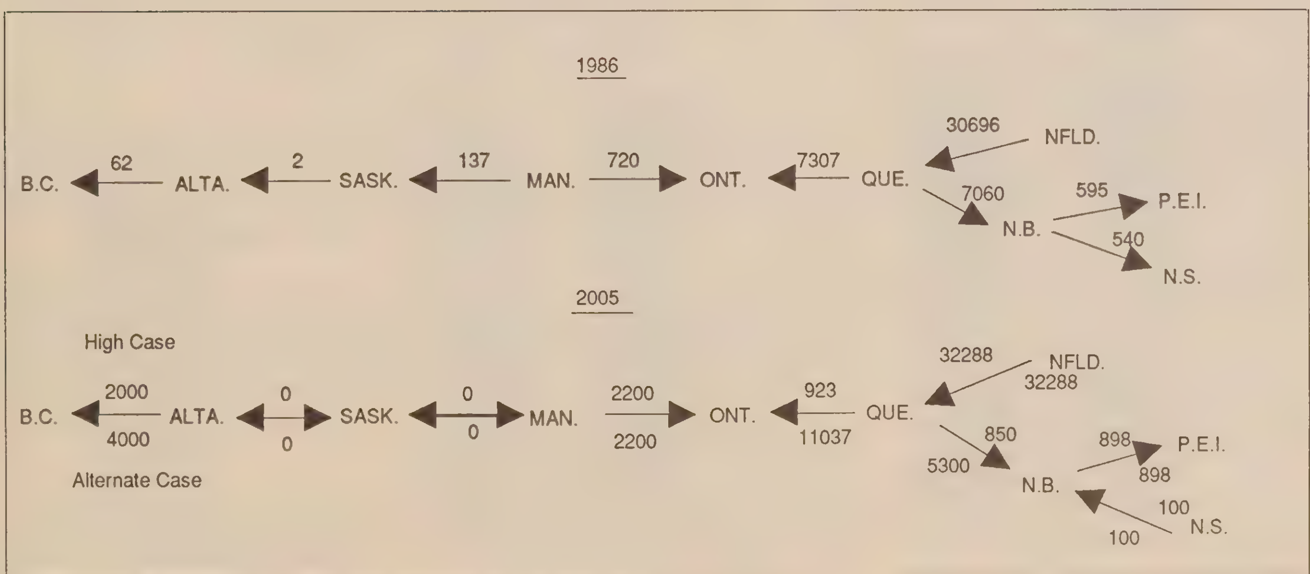
- the sale to Quebec of 4300 megawatts from Churchill Falls in Labrador,
- small firm sales to Prince Edward Island by New Brunswick, and
- a 200 megawatt firm sale by Manitoba to Ontario in the late 1990s.

Provinces such as Ontario and Saskatchewan, which rely on fossil fuels and are adjacent to major hydro-utilities, could opt to purchase capacity rather than to build their own plants. However, their access to inexpensive alternative energy sources, such as coal or nuclear, reduces their attractiveness to potential sellers such as Quebec or Manitoba, when compared with the export market.

Interruptible transactions between provinces are expected to decline in most cases as surpluses decrease. There are two notable exceptions to this:

- In Newfoundland, we assume that energy produced at the projected Gull Island hydro plant in Labrador, which is surplus to Newfoundland requirements, will be sold to Quebec on an interruptible basis. This requires that the two provinces reach a

Figure 5-5
Net Interprovincial Electricity Trade
Gigawatt hours



suitable accord on disposing of energy surpluses from the Gull Island development.

- In Alberta, we project that increased amounts of coal-based energy will flow to British Columbia, to be used either to serve domestic load or to be exported. We assume that these transactions will be interruptible although if they do materialize, they may well be firm.

5.5 Implications for National Capacity Additions and Energy Resource Requirements

The implications of the provincial analysis of the evolution of national generating capacity are summarized for each case in Table 5-16 and Figure 5-6. Because the low case corresponds to a lower overall growth in electricity demand, there is a deferral of generating plant additions relative to the high case, of about 14 gigawatts by 2005.

Table 5-17 lists the major generating projects which provide the bulk of the incremental generating capacity in our two cases.

The capacity available to meet peak loads is projected to grow from about 98 gigawatts in 1986 to about 107 gigawatts in 1990.[1] By 2005, total capacity increases further to about 126 and 139 gigawatts in the low and high cases respectively.

Although our projections of annual demand increases are relatively low, averaging about two percent per year, in absolute terms this represents an average incremental capacity requirement of almost 2 gigawatts per year. In Quebec and Ontario requirements increase at the rate of about one Darlington type nuclear unit (880 megawatts) per year by the end of the study period.

Table 5-16

Supply and Demand of Electricity in Canada

	1986	1990		2005	
		Low Case	High Case	Low Case	High Case
Generating Capacity (GW)[a]	98303	107084	106387	125758	139793
Domestic Peak Demand[b]	72992	76090	78152	96842	107616
System Peak Demand[c]	79176	82974	85021	107040	117814
Remaining Capacity	19127	24110	21366	18718	21979
Percent of System Peak	24	29	25	17	19
Generating Capacity by Fuel Type[d]					
Hydro	56247	57792	57792	71555	79024
Coal	16866	17807	17813	19707	22274
Nuclear	9904	12986	12986	13912	16555
Oil	3620	5771	5771	5799	5969
Natural Gas	2706	2770	2723	3024	2740
Other	3484	3742	3773	4840	6310
Energy Production (TW.h)	457	493	507	620	687
Hydro	309	323	325	385	422
Coal	67	61	71	103	121
Nuclear	67	94	94	101	113
Oil	6	6	7	13	12
Natural Gas	6	6	7	12	12
Other	2	3	3	6	7
Domestic Consumption (TW.h)	**423**	**449**	**463**	**575**	**640**
Net Exports	**34**	**44**	**44**	**45**	**48**

Notes: The numbers in this table have been rounded.
[a] Generating capacity in this table includes purchased capacity.
[b] These numbers are the sum of provincial peak demands, which are not necessarily coincident peaks. To this extent, remaining capacity and percent of system peak values may be understated on a national basis.
[c] System Peak Demand total includes Domestic Peak Demand amount for Newfoundland rather than system peak demand because of a large sales component to Quebec which would otherwise be double counted.
[d] Note that this excludes purchased capacity.

Figure 5-7 summarizes the shares of total Canadian electricity production by type in 1986, and our projections for 1995 and 2005. In 1986, hydro power accounted for about 68 percent of total Canadian generation, nuclear for about 15 percent, and fossil fuels, mainly coal, for the remaining 17 percent. We expect that hydro will continue providing the major share of total electricity production and capacity although coal will be the major source in some provinces.

Total production was 457 terawatt hours in 1986. It is projected to grow to 620 terawatt hours and 687 terawatt hours in 2005 in the low and high cases respectively.

1. Note that this capacity includes reserve credits from interconnections which can be used to meet peak load requirements.

Figure 5-6
Generating Capacity by Type

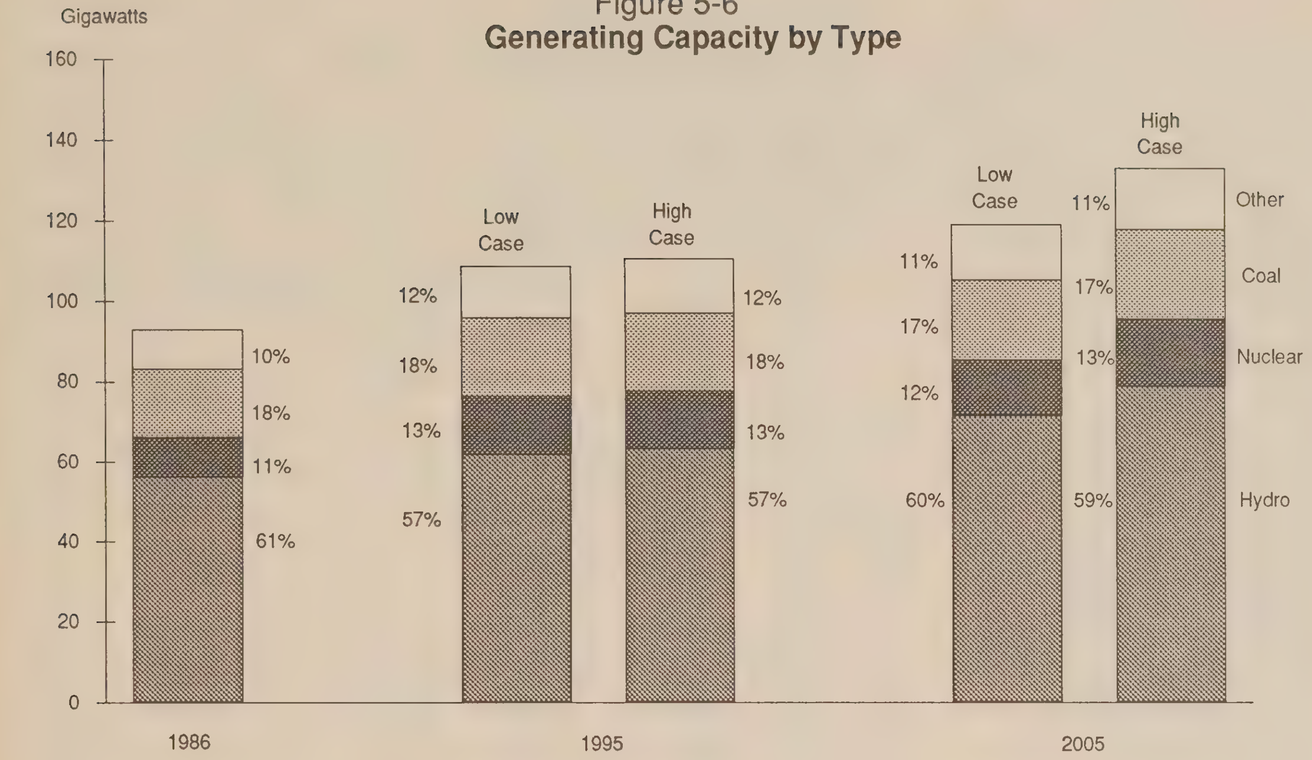
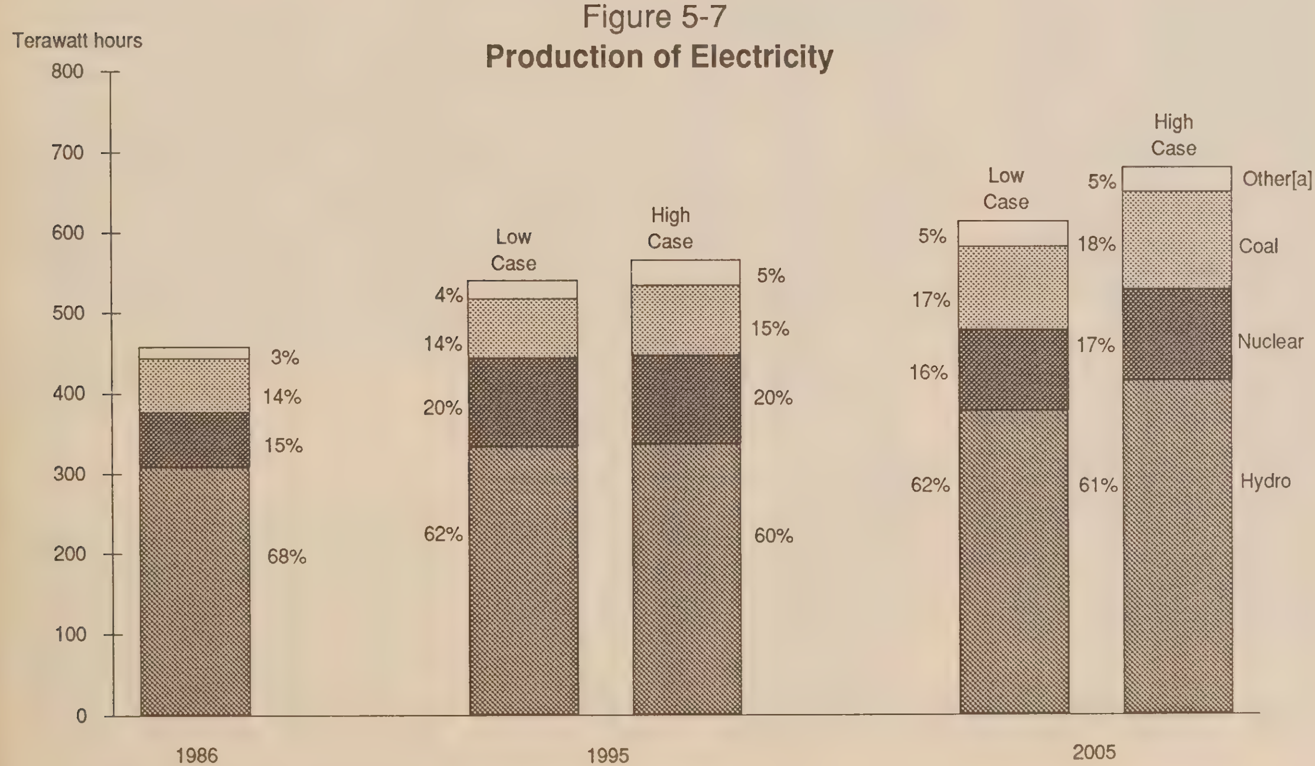


Figure 5-7
Production of Electricity



Note:[a] Includes mainly oil and natural gas

Table 5-17

Timing of Major Projects

Project Description	Approximate In-Service Dates		
	Low Case	High Case	Alternate Case
NEWFOUNDLAND			
New Oil Steam (170 MW)	----	1991	1991
New Oil-Fired 1 (180 MW)	----	1993	1993
New Oil-Fired 2 (180 MW)	----	1993	1993
New Oil-Fired 3 (180 MW)	----	1994	1994
New Oil-Fired 4 (180 MW)	----	1996	1996
New Oil-Fired 5 (800 MW)	----	1997	1997
Tie to Labrador (800MW)	2004	1999	1999
Gull Island (1700MW)	----	2001-2002	2001-2002
NOVA SCOTIA			
Trenton 6 Coal (150 MW)	1991	1991	1991
Cape Breton 1 Coal (150 MW)	1999	1996	1996
Cape Breton 2 Coal (150 MW)	2005	1999	1999
Cape Breton 3 Coal (150 MW)	----	2003	2003
Coal-Export (4 units,1200MW)	----	----	1996-2002
NEW BRUNSWICK			
Coleson Cove 4 Coal (400 MW)	1993	1993	1993
Grand Lake 9 Coal (200 MW)	1994	1994	1994
New Coal (200MW)	----	2003	2001
New Coal (400MW)	----	----	1995
New Coal (200MW)	----	----	2004
QUEBEC			
Manic 5 PA (980 MW)	1989	1989	1989
LG2 A (1900 MW)	1993-1994	1992-1993	1992-1993
LG1 (1296 MW)	1996-1997	1994-1996	1994-1995
Laforge 1 (784 MW)	1999	1995	1995
Brisay (385 MW)	1999	1996	1996
Manic 2 & 3 PA (644 MW)	1995	1997	1996
Sainte Marguerite (822 MW)	2000	1998	1997
Manic 1 PA (191 MW)	1998	1999	1998
Grande Baleine 1 (963 MW)	2000	1999	1998
Grande Baleine 2 (963 MW)	2001	1999-2000	1998
Grande Baleine 3 (963 MW)	2002	2000	1999
Ashuapmushuan (534MW)	2005	2000-2001	1999
Laforge 2 (270 MW)	----	2001	---- [a]
Eastmain 1 (510 MW)	----	2001	----
Eastmain 2 (206 MW)	----	2002	----
Nottaway Broadback Rupert (8700 MW)	----	2002-	2000-
ONTARIO			
Darlington Nuclear 1-4 (3524 MW)	1988-1992	1988-1992	1988-1992
Smokey Falls Hydro (207 MW)	1997	1994	1994
Little Jackfish Hydro (129 MW)	1999	1996	1996
Niagara Redevelopment Hydro (540 MW)	2000	1997	1997
New Nuclear 1 (881 MW)	----	2003	----
New Nuclear 2 (881 MW)	----	2004	----
New Nuclear 3 (881 MW)	----	2005	----

Note: [a] In the alternative case, Nottaway Broadback Rupert is considered more economical to develop ahead of Laforge and Eastmain.

Project Description	Approximate In-Service Dates		
	Low Case	High Case	Alternate Case
MANITOBA			
Limestone (1280 MW)	1990-1992	1990-1992	1990-1992
Conawapa (1290 MW)	1999-2001	1998-2000	1996-1998
Wuskwatim (352 MW)	----	2005	2000
Manasan (249MW)	----	----	2002
First Rapids (200MW)	----	----	2005
SASKATCHEWAN			
Shand 1 (280 MW)	1992	1992	1992
Island Falls Hydro (100 MW)	2000	1996	1996
Wintego (300 MW)	2002	1997	1997
New Coal 1 (280 MW)	----	2000	2000
ALBERTA			
Genesee 2 Coal (406 MW)	1989	1989	1989
Sheerness 2 (383 MW)	1990	1990	1990
Genesee 1 Coal (406 MW)	1991	1991	1991
New Coal 1 (375 MW)	2004	1997	1997
New Coal 2 (375 MW)	----	1999	1999
New Coal 3 (375 MW)	----	2000	2000
New Coal 4 (375 MW)	----	2002	2002
New Coal 5 (375 MW)	----	2003	2003
New Coal 6 (375 MW)	----	2004	2004
BRITISH COLUMBIA			
Mica 5 Hydro (400 MW)	1995	1995	1995
Seven Mile 4 Hydro (202 MW)	2005	1995	1995
Kemano Redevelop. (500MW)	1996	1996	1996
Private Coal (600 MW)	1997	1997	1997
Peace Site C Hydro (900 MW)	----	2002-2003	1999-2000
Keenleyside Hydro (180 MW)	----	2005	2003
Murphy Creek (275MW)	----	----	2004-2005
Hat Creek Coal (500MW)	----	----	2005

Hydroelectricity

In 1986, hydro plants generated 309 terawatt hours, or about 68 percent of total production. By 2005, this source is anticipated to increase to 385 terawatt hours, about 61 percent of total electricity produced in the low case. In the high case, hydro increases to 423 terawatt hours in 2005, also about 62 percent of the total electricity produced. This is equivalent to 1387 and 1522 petajoules of primary energy for the low and high cases, using the energy output method.[1]

Coal

In 1986, about 67 terawatt hours of electricity were generated from coal. This was about 15 percent of the electricity produced in Canada. In order to generate this electricity 796 petajoules of coal were consumed.

We project that the amount of coal-generated electricity will decrease into the early 1990s and then will increase thereafter to 103 and 121 terawatt hours by the year 2005, in the low and high cases respectively. For both cases, this represents about 17 percent of the total electricity produced in 2005. To generate this electricity about 1087 and 1292 petajoules of coal would be required in 2005 for the low and high cases.

Uranium

The amount of electricity generated at nuclear plants was about 67.2 terawatt hours in 1986, almost 15 percent of the total electricity produced. The primary energy contained in the uranium used to produce this electricity corresponds to about 814 petajoules.

We expect nuclear-generated electricity to grow to about 101 and 113 terawatt hours in the year 2005 in the low and high cases. This represents about 16.5 percent of the total electricity production in 2005 and it would require about 1217 and 1372 petajoules of uranium for the two cases.[2]

Oil

In 1986, there were about 6 terawatt hours generated from oil, about 1 percent of the total. The total amount of oil used to generate this electricity was about 60 petajoules.

We are projecting that the amount of oil-generated electricity will increase to 13.9 and 12.6 terawatt hours by 2005 for the low and high cases. For both cases this corresponds to about 2 percent of the total electricity expected to be generated in 2005. This would require 142 and 135 petajoules of oil in the low and high cases respectively.

Natural Gas

In 1986, natural gas was used to generate 6.3 terawatt hours of electricity, about 1 percent of the electricity produced. This required about 58 petajoules of natural gas.

We anticipate that for both cases, natural gas will account for about 1.8 percent of total electricity production in 2005 . About 140 petajoules of natural gas would be required for electricity generation, in both cases. The large amount of gas consumed per unit of electricity production when compared with oil, results from the use of gas mainly to fuel peaking and standby units, which have low energy conversion efficiency.

Other

Electricity generated by other sources amounts to less than 1 percent of total annual generation throughout the period under review. This category includes hog fuel, pulping liquor, coke oven and blast furnace gas, other biomass and fossil fuel by-product sources, and wind and solar power. While these resources will grow in use over the study period, their overall contribution to energy generation is expected to remain small, except in isolated regions where their contribution may be important.

---

1. Since no fuels are used to generate hydro electricity, there are two ways of calculating the primary energy associated with hydro power.
   - We can define its primary energy as the energy produced at the dam site. Measured in this way the primary energy associated with the production of hydro electricity would be equal to the energy content of the electricity output, 3.6 petajoules per terawatt hour. For convenience we label this the energy output method.
   - A second method is frequently used, particularly when comparisons are being made of energy use across countries. This method (labelled the fossil fuel equivalence method) assumes that the amount of primary energy associated with hydro electricity is the amount which would be required if fossil fuels were used. Using this method a conversion factor of 10.5 petajoules per terawatt hour is adopted because methods of generation using fossil fuels have, on average, an efficiency of about 33 percent. Use of the second method implies that the amount of primary energy attributed to hydro will be much larger than the amount of electrical energy produced. It is, however, not relevant for Canada; we have large hydro resources and will not replace our hydro-generated electricity with electricity generated from fossil fuels. We therefore use the energy output method in this report.
2. Nuclear electricity is converted to petajoules using a factor of 12.1 PJ/TW.h.

5.6 Alternative Scenario for Electricity Supply

We view the two cases set out in Section 5.3 to be the most plausible scenarios for supplying domestic needs and for making interprovincial and export sales. They reflect, for the most part, our consultations with utilities, associations and provincial governments. However, in several instances, we had to choose one among a number of plausible assumptions. Accordingly, we present here an alternative supply scenario based on the high case demand. In this alternative we assume greater exports of electricity to the U.S. and more interprovincial trade. Specifically, we made the following changes to the high case assumptions discussed in Sections 5.2.3 and 5.3:

- In Nova Scotia, we added the Cape Breton export project. This entails the construction of a major high-voltage direct-current link from Cape Breton to a point near Boston, Massachusetts by 1997, and the construction of a coal plant of 1200 megawatts in 300 megawatt increments, also starting in 1997.

- In New Brunswick we change the assumption regarding the existing Lepreau I, 230 megawatt nuclear export, such that, instead of expiring in 1994, it is renegotiated to extend to 2005. As well we assume, in addition to the first 400 megawatt coal-fired unit of which half the capacity is dedicated to export beginning in 1993, construction of an identical unit two years later, half the capacity of which is also dedicated to export. We also include a long-term firm purchase of 300 megawatts from Quebec for export to the U.S., starting in 1995 and extending to 2005. The greater volume of exports requires the construction of a second major interconnection with New England in the late 1990s. By the end of the study period, firm exports from New Brunswick total about 930 megawatts.

- In Quebec we assume an additional 1000 megawatts of firm exports beyond the 3100 megawatts included in the high case. As well, we project that Quebec sells 2000 megawatts on a firm basis to Ontario in 1998 and 300 megawatts to New Brunswick. Quebec accelerates its construction program to accommodate this increased out-of-province demand. In this scenario, Quebec develops most of its more economical projects by the end of the study period.

- In Ontario the purchase of 2000 megawatts from Quebec reduces the need for new generating capacity early in the next century and results in a deferral of new nuclear additions by about 3 years.

- In Manitoba, we assume a 500 megawatt export to utility groups in the U.S. to begin in 1995 and a second 500 megawatt firm export to begin in the year 2000. This brings the total firm export from Manitoba to about 1500 megawatts by the year 2000.

- In Alberta we assume the sale of an additional 2000 gigawatt hours per year of interruptible energy to British Columbia. This brings the total sales to about 4000 gigawatt hours per year by the early 1990s.

- In British Columbia, we assume the completion of the 900 megawatt Site C hydro project in the year 2000, all of it for export. As well, we include an increased export of interruptible energy as a result of increased inflows from Alberta as described above.

These alternative assumptions reflect projects which are either being actively considered by the various provinces or which are consistent with their marketing strategies. They represent a plausible, though, in our view, less likely alternative. Table 5-17 details the effect of these assumptions on the development plans within each affected province. Table 5-15 shows the projected exports by province compared with those in the high case and Figure 5-3 illustrates the effect of these assumptions on total exports. The implications of our alternative assumptions on interprovincial trade are illustrated in Figure 5-5.

In the alternative case, relative to the high case, by 2005:

- Net exports are about 50 percent greater (an increase from about 48 to 71 terawatt hours).

- Most of the increase of net exports is shared between New Brunswick, Quebec, Manitoba, and British Columbia, New Brunswick's being the largest at 7.5 terawatt hours, and the others in the range of 4 to 6 terawatt hours each.

- Excluding flows from Churchill Falls to Quebec, interprovincial trade more than triples, from 6971 GW.h to 23 535 GW.h, most of it being from Quebec to Ontario and New Brunswick. This increases the share of inter-

provincial trade in total energy production from about 1 percent to about 3.5 percent.

5.7 Conclusion

Our review leads us to conclude that there will be ample supplies of basic energy resources to generate electricity over the study period even with electricity prices increasing only at the rate of inflation. However, the need for new facilities implies a substantial construction program, despite our relatively low load growth rate projections.

In some provinces (Quebec, New-Brunswick, Manitoba, British Columbia) we expect firm export contracts to be signed which will result in the pre-building of generating plants or the dedicating of specific projects to export markets.

In other provinces, particularly Ontario, the problem will be to accommodate a relatively high rate of demand growth in a manner consistent with environmental protection while dealing with the long construction lead times for new projects. Part of the solution for these provinces will be to rely more heavily on demand-side management to bridge the gap until new facilities can be brought into service.

Even though it has still to be fully developed, a significant potential for mutually beneficial interprovincial trade exists between adjacent provinces in the West as well as in the East. This potential for trade, combined with the possible contributions of non-utility producers, widens the range of supply options which utilities can pursue. This range of options is highlighted by our alternative supply case as well as our low and high cases.

Chapter 6

Natural Gas

We begin the chapter with a discussion of natural gas resources. This section includes our estimates of established reserves. We then develop our estimates of reserves additions for the Western Canada Sedimentary Basin and describe the methodology used to estimate the associated supply costs. We next project the productive capacity from all sources which are expected to contribute to supply over the projection period. We then look at exports, and bring together the supply and demand profiles, taking account of both domestic and export demand. We end the chapter with a discussion of the implications of our projections.

6.1 Resources

The natural gas resource base includes all sources of natural gas, including unconventional sources such as very low permeability reservoirs, coal seams and the gasification of coal.[1]

Canada's current natural gas supply is from conventionally producible resources, primarily in western Canada. Over time, as this production declines, the nation will become increasingly dependent on higher cost resources, from both the traditional producing and frontier regions, and eventually unconventional resources will play a role.

In this report we introduce two terms: "technically recoverable resources", resources recoverable with current technology but not necessarily recoverable economically, and "economically recoverable resources", those judged to be both technically and economically recoverable. An estimate of the size of an economically recoverable resource will be related to a particular price. The use of these classifications allows us to further refine our approach to the assessment of Canadian hydrocarbon supply.

6.1.1 Technically Recoverable Resources

Different approaches have been used to estimate quantities of natural gas that might ultimately prove technically recoverable. Such estimates can change considerably over time as new technologies are developed and geological knowledge is accumulated. In this report, we have made use of the resource estimates of the Geological Survey of Canada (GSC), compiled in 1983,[2] which are based on an evaluation of individual exploration plays. Both objective data and informed geological opinion formed the basis for the evaluation. No explicit price assumptions accompanied the estimates.

We have not used the concept of technically recoverable resources in previous studies. Rather, we used as our resource base the "ultimate potential", which by definition is influenced by economic conditions, including price. We determined ultimate potential by extrapolating the historical trend of reserves additions. This approach we consider no longer appropriate since it provides no means of estimating potentials at various prices. Our current approach to ultimate potential, or "ultimate economic potential" as it might more explicitly be termed is discussed in Section 6.3.

Western Canada

The GSC estimates of the undiscovered technically recoverable resource[3] of the Western Canada Sedimentary Basin (WCSB) range from some 60 exajoules, at high confidence, to a speculative value of approximately 190 exajoules. The Survey's "average expectation" or mean value is 95 exajoules. When we add to these estimates of undiscovered quantities the 130 exajoules of gas discovered up to the time the estimates were made, we obtain estimates of the *ultimate* technically recoverable resource. The base on which we have built our supply projections for this report is the ultimate value at average expectation, namely 225 exajoules. We believe there is a reasonable probability that the

---

1. Gas from coal is not discussed in this report, since it is unlikely to contribute to supply within the projection period.
2. R.M. Procter, G.C. Taylor and J.A. Wade, *Oil and Natural Gas Resources of Canada 1983,* Geological Survey of Canada Paper 83-31.
3. The GSC uses the equivalent term "undiscovered resource potential".

technically recoverable resource will prove to be at least this large, but this is not certain.

For purposes of this update, Western Gas Marketing Limited (WGML) provided us with a study indicating that the ultimate technically recoverable resource in western Canada could exceed 300 exajoules. The company used a regionally disaggregated statistical approach in arriving at this estimate.

The GSC and WGML estimates are compared in Table 6-1. The wide range emphasizes the high degree of uncertainty involved in the assessment of resource potential. Supply projections are, of course, critically dependent on the assumptions made with respect to the size and other characteristics of the resource from which the supply is to be obtained.

The GSC did not consider in its resource estimates any portion of the unconventional gas resource occurring in very low permeability (so-called "tight") reservoirs in west-central Alberta and the adjacent sector of northeastern British Columbia. The methodology employed by WGML suggests that its estimate may include some gas in this category. This resource may in future make a substantial contribution to western Canada gas supply, but because there is little history of production we do not believe we have sufficient information to estimate how much of the resource may be technically recoverable. To the extent that gas from this source becomes available within our study period, supply projections will be understated.

Frontier Areas

Much less is known about the gas resources of these areas than about those of the Western

Table 6-1

Ultimate Technically Recoverable Resources
Western Canada Sedimentary Basin

(Exajoules)

Geological Survey of Canada (1983) [a]	
High Confidence	190
Average Expectation	225
Speculative Estimate	320
Western Gas Marketing (1987)	319 [b]

Notes: [a] Estimated from undiscovered resource data published by the Geological Survey.
[b] Alberta, northeastern British Columbia and Saskatchewan.

Table 6-2

Technically Recoverable Natural Gas Resources
Frontier Areas

(Exajoules)

	(at 31 December 1987) Discovered	Undiscovered
West Coast	0	10
Mainland Territories	1	12
Mackenzie Delta and Beaufort Sea	11	80
Arctic Islands and Eastern Arctic Offshore	16	118
Hudson Bay	0	3
Grand Banks and Labrador Sea	5	48
Nova Scotia Offshore	6	25
Total	**39**	**296**

Source: The Canada Oil and Gas Lands Administration Annual Report 1987.

Canada Sedimentary Basin. A relatively small proportion of the resources estimated to exist have actually been discovered, and there is no production history.

Based on the GSC's 1983 data, the ultimate technically recoverable resources of the frontier regions range from some 135 exajoules at high confidence to a speculative value of more than 500 exajoules. The Survey's average expectation value is about 290 exajoules.

The Canada Oil and Gas Lands Administration (COGLA) has published estimates of both the discovered and undiscovered technically recoverable resources of the frontier areas. These are shown in Table 6-2. The total of the two categories, 335 exajoules, constitutes an estimate of the ultimate technically recoverable resources. This estimate is compared with the corresponding estimates of the GSC in Table 6-3.

In 1988, the Canada-Newfoundland Offshore Petroleum Board published its estimates of the discovered resources of the Northeast Grand Banks Region. Its estimate for the region is approximately 4 exajoules.

6.1.2 Economically Recoverable Resources

We define the economically recoverable resources as that component of the technically recoverable resources deemed economic to produce under specified economic conditions.

Our estimate of the ultimate economically recoverable resources of the Western Canada Sedimentary Basin is approximately 205 exajoules for both the low and high cases. The derivation of this estimate is discussed in Section 6.3.

6.2 Remaining Established Reserves

That part of the economically recoverable resources which has been discovered we term "established reserves". Those established reserves not yet produced are termed "remaining established reserves".

We estimate Canada's remaining established reserves of marketable natural gas at 31 December 1986 to be 92.9 exajoules, of which 75.3 exajoules are in the conventional producing areas and 17.6 exajoules in the Mackenzie Delta and Arctic Islands. We have not to date assigned any of the discovered resources of the east coast offshore to the established category, primarily because of the uncertainty surrounding their economic viability.

This estimate of remaining reserves is 3.3 exajoules less than the year-end 1984 estimate published in the October 1986 Report. Reserves declined in both 1985 and 1986, because reserves additions in the conventional areas were insufficient to replace reserves produced. Additions were 1.9 exajoules and 1.3 exajoules respectively; production was approximately 3 exajoules in each year. Table 6-4 shows the components of the changes to remaining reserves for the years 1982 to 1986, and Table 6-5 shows the regional composition of year-end 1985 and 1986 remaining reserves estimates.

Our preliminary estimate for year-end 1987 of 89.9 exajoules represents a further decrease in remaining established reserves of

Table 6-3

Ultimate Technically Recoverable Resources Frontier Areas

(Exajoules)

Geological Survey of Canada (1983) [a]	
High Confidence	135
Average Expectation	290
Speculative Estimate	500
Canada Oil and Gas Lands Administration (1987)	335

Note: [a] Geological Survey estimate excludes those for the mainland Territories.

some 3.0 exajoules. This is the fifth consecutive year that remaining reserves have declined due to declines in the conventional areas. Figure 6-1 traces the history of remaining and initial (before production) established reserves of marketable natural gas in the conventional areas since 1965.

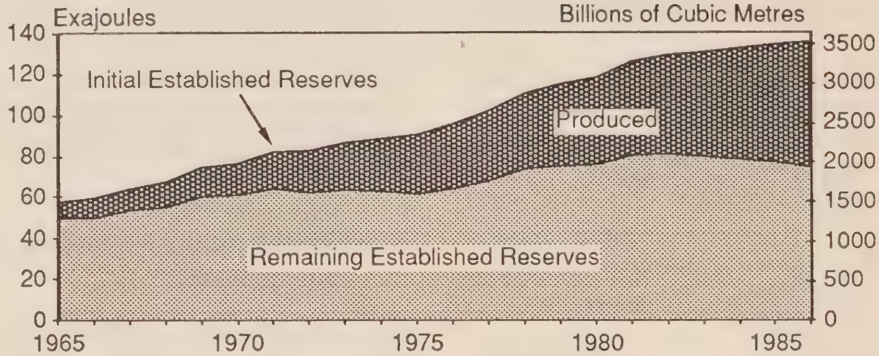
In our 1986 report, we called attention to the possibility of overstatement of the reserves we were crediting to Alberta pools with initial reserves of 10 petajoules or less. There are currently some 19 000 pools in this size category in the province, to which we assign established reserves of approximately 27 exajoules. The average pool size is about 1.5 petajoules.

Since pools in the 10 petajoule or less size range are expected to make an important contribution to future supply, we decided that a critical examination of the characteristics of the current inventory of these pools was warranted. As the first step, we examined the historical production performance of most of the some 5500 pools which are producing or had at one time produced. On the basis of our studies, we concluded that their reserves had been overstated by 2.8 exajoules, or by approximately 25 percent, and reduced our estimates for these pools accordingly. Part of the reduction is reflected in the low value of revisions and extensions to reserves for 1986, shown in Table 6-4.

We have to date made no adjustment to the reserves of the more than 13 000 small pools in Alberta which have not yet been placed on production. Many of these are single well pools, to which it was necessary to assign arbitrary acreage factors in order to estimate their reserves. Since the earlier overestimation of the reserves of

Figure 6-1

Established Reserves of Marketable Natural Gas Conventional Areas



Source: Appendix Table A6-1

Table 6-4

Marketable Natural Gas Remaining Established Reserves in Conventional Areas

(Exajoules)

	Remaining Reserves Beginning of Year	Additions			Production	**Remaining Reserves Year-end**
		Discoveries	Revisions & Extensions	Total		
1982	80.8	0.7	2.8	3.5	2.8	**81.5**
1983	81.5	0.7	0.7	1.4	2.7	**80.0**
1984	80.0	0.4	1.1	1.5	2.9	**78.6**
1985	78.6	0.6	1.3	1.9	3.2	**77.3**
1986	77.3	0.5	0.8	1.3	3.1	**75.3**

Note: Numbers may not balance due to adjustments to the cumulative production.

Table 6-5

Remaining Established Reserves of Marketable Natural Gas

at 31 December

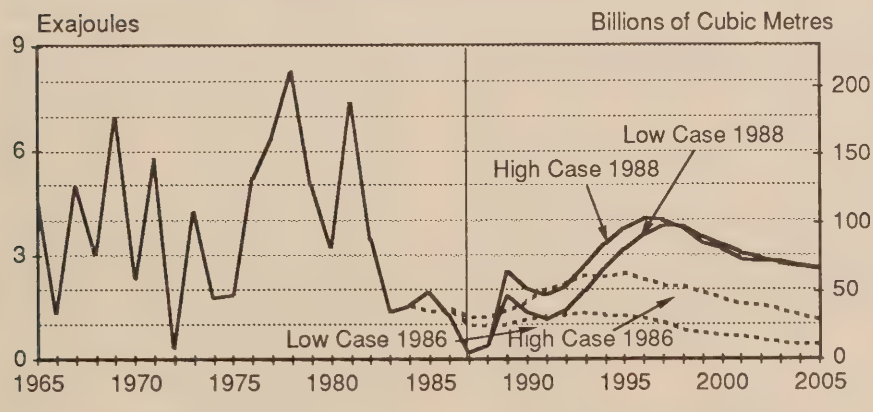
(Exajoules)

	1985	1986
British Columbia	8.9	8.8
Alberta	65.6	63.9
Saskatchewan	2.0	1.9
Southern Territories	0.4	0.3
Ontario and Other Eastern Producing Areas	0.5	0.4
Total Conventional Areas	**77.3**	**75.3**
Beaufort Sea/Mackenzie Delta	5.6	5.6
Arctic Islands	12.0	12.0
Total Canada	**94.9**	**92.9**

Note: The numbers in this table have been rounded.

Figure 6-2

Marketable Natural Gas Reserves Additions Conventional Areas



Source: Appendix Table A6-2

the producing pools was found to have resulted in part from the use of acreage factors that were too large, it follows that overstatement of the reserves of the non-producing segment is likely.

6.3 Reserves Additions - Conventional Areas

In a market environment the price of natural gas will change, tending to balance supply and demand. The major source of new natural gas supplies to maintain this balance over the projection period will be the conventional producing areas of western Canada. We estimate annual reserves additions from this source by assuming that, once the current deliverability surplus ends, reserves will be added at a rate to maintain an approximate balance between productive capacity and demand. Fieldgate prices are assumed to vary over time such that producers' costs and resource owners' economic royalties for these additions will be covered. As previously discussed, the procedure iterates between our supply and our demand analyses, yielding prices which are consistent with the demand to be satisfied at those prices and with the development of the required supply. We also verify that the industry can achieve the annual levels of exploratory drilling necessary to provide the required reserves additions.

The estimated annual reserves additions of natural gas required to maintain the supply and demand in balance for the low and high cases are compared with the estimates from the October 1986 Report in Figure 6-2. Net annual reserves additions in 1986, 1987 and 1988 are close to zero because the discoveries in these years are offset by downward revisions to reserves

of small pools. Annual reserves additions after 1992 are projected to be considerably larger than those we projected in the October 1986 Report. Over the projection period they average 2.4 exajoules in the low case and 2.7 exajoules in the high case. By way of comparison, actual reserves additions during the period from 1980 to 1986 averaged 2.9 exajoules per year (Appendix Table A6-2).

A total of 46 exajoules of natural gas from the conventional areas is projected to be added over the projection period in the low case and 51 exajoules in the high case (Appendix Table A6-3). These compare with 17 and 34 exajoules respectively in the October 1986 Report over the same period.

To motivate producers and resource owners to bring on new natural gas supplies, the price the producer receives must cover the total cost of bringing on these new supplies. This total cost is referred to as the replacement cost or the incremental supply cost; it is the sum of the incremental direct cost and the user cost, less the credit for by-products (natural gas liquids and sulphur).

The *incremental direct cost* is the estimated cost per gigajoule of natural gas associated with the reserves additions in any given year. It includes the costs for exploratory and development drilling, geological and geophysical assessment, field equipment including field gas plants and production. The cost of all capital employed is taken into account by assuming before tax real rates of return of 10 and 15 percent for the low and high cases respectively. As explained in Section 3.1, we expect that lower returns to capital would be acceptable in the economic environment of the low case relative to what would be required in the high case.

The basic costs used for our estimation of future incremental direct costs are shown in Table 6-6. These costs are based on historical data. In the low case we assume that the industry will respond to the challenge of lower oil prices by reducing costs through technological development and other cost cutting measures. We referred to data on actual costs for 1986,

Table 6-6

Unit Costs for Natural Gas

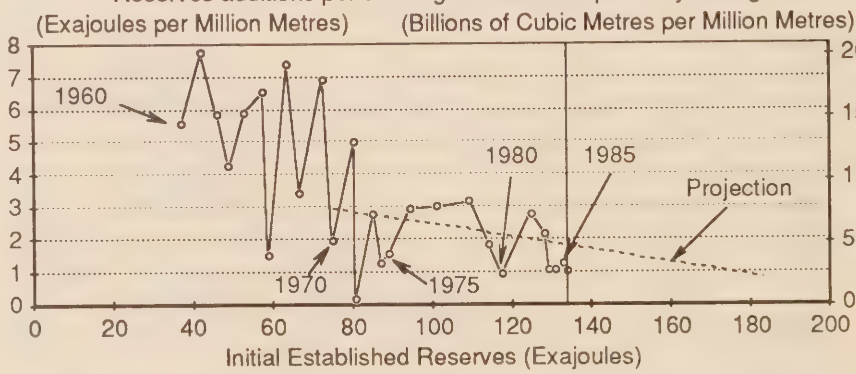
	Low Case	High Case
Exploratory Drilling ($C /m)	350.00	450.00
Development Drilling ($C /m)	200.00	260.00
Field Equipment ($C 1000/well)	200.00	250.00
Gas Plants ($C /GJ of additions)	0.10	0.11
Fixed Costs per year ($C 1000/well)	25.70	28.50
Variable Cost ($C /GJ)	0.20	0.22

Note: Geological and geophysical costs are assumed to be 20 percent of exploration and development drilling costs in both cases.

Figure 6-3

Trend In Rate Of Natural Gas Reserves Additions Conventional Areas

Reserves additions per unit of gas-directed exploratory drilling



Source: Appendix Table A6-2

when the price of oil was low, to derive representative costs for this case. In the high case we used data on actual costs for earlier years when the price of oil was higher.

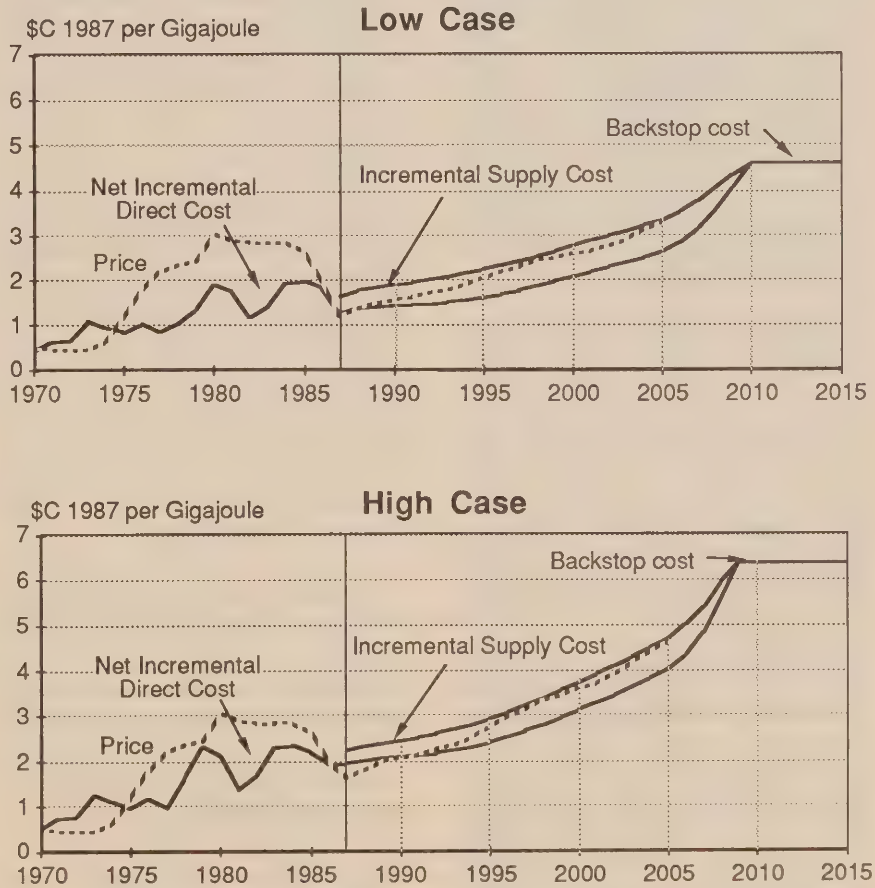
Reserves additions of natural gas per metre of exploratory drilling have been declining and we project a continuation of this decline as prospects for new discoveries diminish. As a result, incremental direct costs per unit of reserves discovered increase with cumulative reserves additions over time. Figure 6-3 illustrates the decline in reserves additions of natural gas per unit of gas-directed exploratory drilling in conventional areas that we use as a basis for our estimate of incremental direct costs. As shown, we assume a linear decline rate from current levels to reach zero at 225 exajoules, the GSC average expectation for the ultimate technical potential for natural gas in the Western Canada Sedimentary Basin. Historical data show that reserves connected per development well have also been declining and we assume that this trend will continue, resulting in an increase of development costs over the projection period.

The by-products of natural gas processing at field gas plants are natural gas liquids and sulphur. Revenues received for these products in effect reduce the costs of natural gas production and we therefore include them as a credit in the estimation of the *net incremental direct costs*. To calculate this credit we assume that future prices for propane, butanes and pentanes plus will be related to the price of crude oil in the same proportion as they have been over the period 1970 to 1986. Ethane is currently priced at the price of natural gas plus the cost of service for extraction. We assume for the purposes of this calculation that this pricing mechanism will be maintained throughout the projection period. For sulphur we assume that prices will remain constant in real terms at approximately \$C 80 per tonne, reflecting the current value. The estimated net incremental direct costs associated with increments of reserves additions resulting from these estimates are given in Appendix Table A6-4 for the two cases.

The *user cost* (defined in Section 3.1) is calculated as the net present value of future cost increases resulting from an incremental unit of production in any given year. To make this calculation, we begin with a base stream of increasing net incremental direct costs per gigajoule as shown in Figure 6-4 for the low and high cases respectively. We then increase production of gas in the selected year by one unit (since the user charge is intended to reflect the appropriate compensation for producing natural gas now rather than leaving it in the ground until a future time when it has increased value). This has the effect of advancing the stream of direct costs, relative to those of the base stream, for all future years. We discount both the base and advanced streams of direct costs to obtain their present value and subtract the present value of the base stream from that of the

Figure 6-4

Fieldgate Supply Costs and Prices For Natural Gas



Source: Appendix Table A6-4

advanced stream. The result is the per gigajoule user cost for the year selected. We repeat this process for each year of the projection period to obtain the user cost for each year.

Two factors influence the value of the user cost; the discount rate and the backstop value. The lower the discount rate, the higher the user cost because lower discount rates give higher present worth to future values than do higher discount rates. We use discount rates of 10 and 15 percent for the low and high cases respectively. The backstop value is the lesser of the highest cost unit of gas likely to be produced at some future time, or the value of the most easily substitutable fuel. The higher this backstop value, the higher the user cost. We use backstop values of \$C 4.60 per gigajoule and \$C 6.40 per gigajoule for the low and high case respectively. These reflect the assumed value of the most easily substitutable fuel, light fuel oil in the low case and in the high case the unit cost of large volumes of gas either from the frontier regions or from alternative sources such as coal gasification.

In Figure 6-4 the user cost is the difference between the incremental supply cost curve and the net incremental direct cost curve. Also shown in Figure 6-4 are the estimated fieldgate prices of natural gas for western Canada. The supply cost projections have been extended to the backstop values.

Given our estimate of technical potential, resources in conventional areas that would become economic at prices equivalent to these backstop values ultimately amount to about 205 exajoules in both the low and high cases. By way of comparison, in the October 1986 Report we used an ultimate economic potential of 185 exajoules as a basis for our estimates of reserves additions.

Supply from the Beaufort-Mackenzie Delta region is projected to become economic in 1999 when the fieldgate price in western Canada is projected to be about \$C 2.50 per gigajoule in the low case and \$C 3.50 per gigajoule in the high case. (Equivalent to about \$US 2.40/MMBTU and \$US 3.30/MMBTU respectively at Caroline, Alberta. To determine an equivalent price at Caroline of Alberta sourced natural gas, we add the Alberta cost of service to the average Alberta fieldgate price.) The commencement of production of frontier natural gas at this time has a small depressing effect on prices because it creates a temporary excess of supply. This happens because the project must be developed at a minimum productive capacity, which for a short period of time exceeds incremental domestic and export demand. Supply from the east coast offshore is assumed to come on stream in 2004 in the high case when the fieldgate price in western Canada is approximately \$C 4.50 per gigajoule. The equivalent city gate price at Boston would then have to be about \$US 5.70/MMBTU. In the low case, east coast offshore gas reservoirs would not commence production during the projection period because of unfavourable economics.

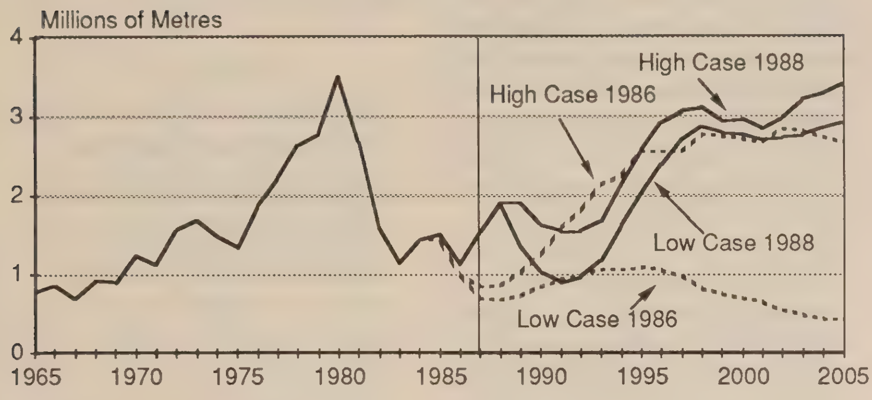
To assess whether the estimated reserves additions are feasible given the prospective size of the rig fleet we estimate exploratory drilling levels necessary to bring on the reserves additions required to maintain natural gas supply and demand in balance.

It is not possible to determine if an individual well was drilled with the intent of finding natural gas or crude oil. Accordingly, for historical data we use drilling results to make the division. Wells which discovered natural gas are classed as gas-directed, whereas those which found crude oil are classed as oil-directed. The abandoned wells in each year are assigned to one of these categories in the same ratio as the successful wells. These historical levels of gas-directed and oil-directed drilling are then used as a basis for our estimates of historical additions rates for conventional areas shown in Figures 6-3 and 7-3.

For each annual reserves addition we estimate the required annual gas-directed exploratory drilling on the basis of the projection of the additions rate curve shown in Figure 6-3. The results of this analysis are compared in Figure 6-5 with our previous estimates in the October 1986 Report. The drilling activity for 1987 is higher than we anticipated in 1986 because of government incentive programs such as the federal CEDIP program and the enhanced new well royalty holiday regulations of the producing provinces.

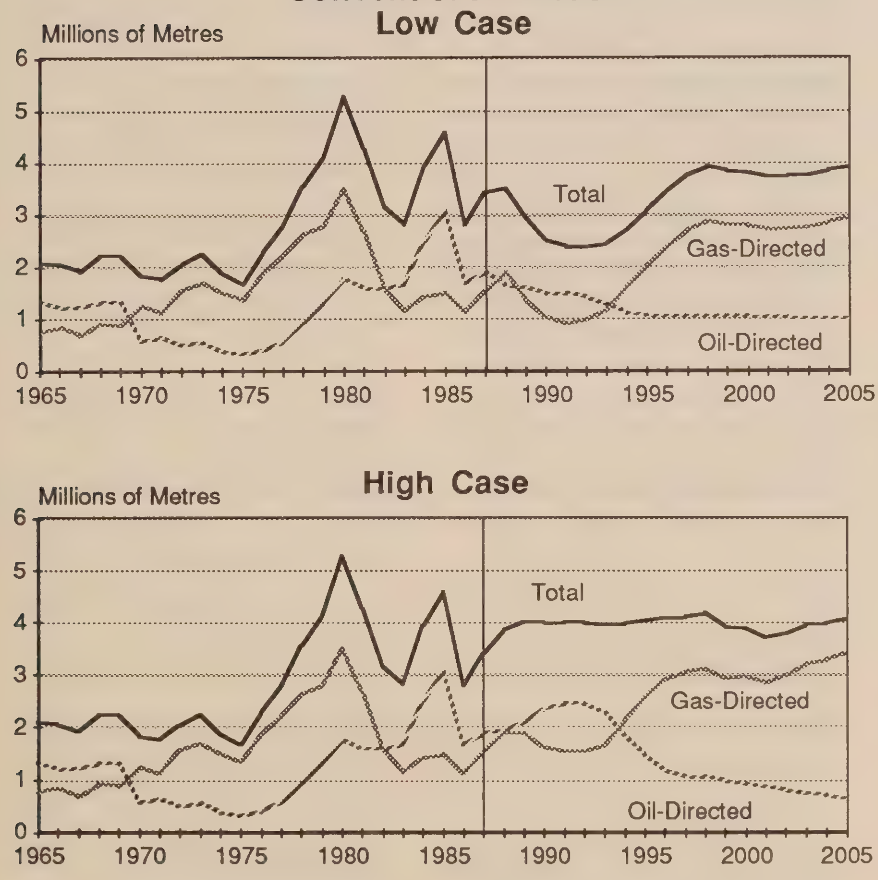
The differences between our current projections and those of the October 1986 Report are due to our revised assessment of the ultimate potential for the conventional areas and to our new assumption that fieldgate prices for natural gas will adjust such that an approximate balance will be maintained between supply and demand. In the current analysis gas-directed drilling increases rapidly in the mid-1990s when supply and demand approach a balance in both the low and high cases. During the latter part of the projection period gas-directed drilling is higher than previously in both cases.

Figure 6-5
Gas-Directed Exploratory Drilling Conventional Areas



Source: Appendix Table A6-2

Figure 6-6
Division of Exploratory Drilling Conventional Areas
Low Case



Source: Appendix Tables A6-2 and A7-5

We obtain estimates of total exploratory drilling for each year of the projection period by summing the individual estimates for gas-directed and oil-directed activities. The results of this analysis are shown in Figure 6-6.

In the low case, total exploratory drilling declines from current levels to a trough in the early 1990s, rising thereafter to almost 4 million metres per year because of increasing gas-directed activity.

In the high case, total exploratory drilling rises from current levels to approximately 4 million metres per year by the early 1990s and remains at roughly this level thereafter. From the present time to the early 1990s exploratory drilling is projected to be largely oil-directed because of rising oil prices and excess natural gas supply. From the mid-1990s the activity becomes increasingly gas-directed. Estimated levels of exploratory drilling required to bring on the natural gas reserves additions to maintain the natural gas supply/demand balance over the projection period are less than peak levels achieved in the recent past. Consequently we conclude that our projected drilling levels could be achieved by industry.

6.4 Productive Capacity

This section explains how we derived our projections of the productive capacity of natural gas. Following some general comments concerning overall assumptions and methodology we discuss our projections for each reserves category and in total.

Productive capacity is the estimated rate at which natural gas can be produced from a well, pool or other entity, unrestricted by

demand, but having regard to reservoir characteristics, economic considerations, contractual and regulatory limitations, the feasibility of infill drilling and/or addition of compression, the availability of processing facilities and potential losses due to mechanical breakdown.[1]

Our projections of productive capacity are different in the two cases because of the different price projections. The greatest impact of prices is on the rate of reserves additions, which provide an increasing proportion of productive capacity over the projection period. Natural gas prices also affect the timing of infill drilling and addition of compression so that slightly different productive capacity projections for currently established reserves result. The rates of connection for currently established reserves which are not yet contracted could also be different with different prices, but since the effect on productive capacity is expected to be relatively minor, we assumed the same connection rates in both cases.

Our estimates represent the productive capacity immediately available from all connected reserves, plus that which could be made available from both connected and unconnected reserves and from reserves additions within about six months. These projections include productive capacity from some infill wells which, although we consider them economic on a stand-alone basis, may not be drilled because of an individual producer's particular economic situation. For these reasons, our estimates for the early years of the projection period will be higher than productive capacity immediately available. Our projections are not constrained by the gathering and transmission capacity of pipeline systems.

We project productive capacity differently for currently established reserves under contract than for those which are not yet contracted; accordingly, we have made the following assumptions relating to the contractual status of established reserves:

- For British Columbia, we included in the contracted category only those reserves dedicated to Westcoast Energy. All other reserves, including those dedicated to small British Columbia local utilities and short-term exporters other than Westcoast we placed in the uncontracted category, since we do not have the information to identify what is under contract.

- For Alberta, we placed in the contracted category all reserves identified by the ERCB[2] as being contracted, all other reserves which are currently producing, all solution gas reserves, all deferred gas reserves and all southeast Alberta shallow gas reserves. All other reserves in the province except those identified at this time as beyond economic reach we included in the other uncontracted category. In effect, the other uncontracted category represents essentially all gas currently available for contracting in Alberta.

- For Saskatchewan, we assumed that some 60 percent of the reserves are contracted. Actual data on contracted reserves is unavailable.

- For the southern Territories and eastern Canada, we assumed that all reserves are contracted.

This breakdown of remaining currently established gas reserves in the conventional areas is summarized in Table 6-7.

Table 6-7
Disposition of Remaining Established Reserves of Marketable Natural Gas Conventional Areas

at 31 December, 1986

(Exajoules)

British Columbia		**8.8**
Contracted to Westcoast	5.5	
Uncontracted	3.3	
Alberta		**63.9**
Contracted [a]	48.2	
Deferred	6.3	
Beyond Economic Reach	2.0	
Other Uncontracted	7.4	
Saskatchewan		**1.9**
Contracted	1.1	
Other	0.8	
Southern Yukon and N.W.T		**0.3**
Ontario and Other Eastern Areas		**0.4**
Total Conventional Areas		**75.3**

Note :[a] Includes 5.7 exajoules of shallow southeast Alberta gas reserves and 2.8 exajoules of solution gas reserves

To arrive at our overall productive capacity estimates we have examined the productive capacity of four specific categories of reserves, the first three of which relate to gas in the conventional areas:

- currently established reserves under contract,

1. Productive capacity is estimated at the field plant exit point, or at the wellhead if field processing is not applicable. Estimates exclude quantities of NGL removed at field plants, but include amounts removed later at straddle plants.
2. ERCB Gas Purchasers File.

- currently established reserves not as yet contracted,
- reserves additions, and
- frontier gas.

Established Reserves Under Contract

We derived our projections of productive capacity[1] for all gas pools in British Columbia assuming initial contract rates of 1:5750 (1 unit of production for each 5750 units of initial gas reserves). This rate reflects historical contracting practices in British Columbia, and is expected to remain representative for the future.

The Alberta contracted reserves excluding shallow southeast Alberta and solution gas reserves are 39.7 exajoules. We derived our projections of productive capacity from these reserves assuming that 75 percent would be produced at the 1:7000 rate of take representative of historical long-term contracting practices, and 25 percent at a 1:3500 rate of take characteristic of many contracts entered into in the late 1970s and early 1980s. Our consultations confirmed that this approach was reasonable.

We derived productive capacity projections for the two major components of the 5.7 exajoules of remaining shallow gas reserves in southeast Alberta as follows:

- for the Milk River/Medicine Hat pools, our productive capacity projections were derived by field using a production decline analysis of producing wells,
- for the Second White Specks gas pools we projected productive capacity based on individual reservoir and well flow characteristics.

We projected the infill drilling required to fully develop the fields, maintaining a constant level of production as long as possible. Not all these shallow gas reserves are currently under contract, but since there is no basis for determining startup dates for those pools not under contract, we made the assumption that they are now all producing for the purpose of projecting productive capacity. This assumption could result in some overestimation of productive capacity in the early years of the projection period.

There are some 2.8 exajoules of solution gas (gas dissolved in oil reservoirs) in Alberta. We based our projection of solution gas productive capacity on our projection of the productive capacity for the relevant oil pools and a projection of gas to oil ratios in those pools.

We based our projection of productive capacity from all Saskatchewan reserves on a projection provided for this report by the Saskatchewan government.

We projected productive capacity for the Kotaneelee field in the southern Yukon and the Pointed Mountain field in the southern Northwest Territories on an individual pool basis.

Our estimates of productive capacity for Ontario (and Quebec, which has very minor production) are based on historical trends.

Established Reserves Not As Yet Contracted

For this category, future contracting practices, and thus the rates at which the reservoirs will be produced, will reflect the nature of the gas market. Though there is a move towards shorter term contracts in some sectors of the market, we expect long-term natural gas supply contracts to prevail in certain domestic and export markets such as co-generation electric power facilities which require long-term commitments of gas.

For those gas pools not currently contracted in British Columbia, some 3.3 exajoules, we assigned initial production dates based on their proximity to existing pipelines and anticipated pipeline expansions, and projected productive capacity on the same basis as contracted British Columbia reserves discussed above.

For Alberta, we assumed that of the 7.4 exajoules of reserves in the other uncontracted category, 50 percent would be produced at initial rates of take of 1:7000 and 50 percent at 1:3500. This composite deliverability profile was then used to develop a projection of productive capacity using the same connection schedule as that in the October 1986 Report (5, 5, 10, 15, 15, 15, 15, 10, 5, and 5 percent per year). This connection profile was designed so that minimal new productive capacity would be developed in the early years of the

1. Productive capacity from all gas reserves in British Columbia and all gas reserves in Alberta except deferred reserves and reserves beyond economic reach was derived on a pool by pool basis. The projections reflect each gas pool's well flow characteristics, basic reservoir parameters and daily contract rate. They also incorporate drilling and compression cost data and projected producer netbacks to assess the time period over which productive capacity can be maintained at contract rates or as high as possible under contract rates by adding infill wells and/or field compression.

projection period while substantial excess productive capacity persists.

The Alberta ERCB identifies some 6.3 exajoules of deferred gas reserves in Alberta as of 31 December 1986. We based productive capacity from some 50 percent of the deferred gas reserves in the province, principally gas associated with oil reservoirs, on previous estimates provided by TransCanada on a pool by pool basis. The remainder of these reserves are reserves deferred for enhanced oil recovery schemes and are not expected to be available for the market over the projection period.

We assume that all Alberta reserves considered beyond economic reach at this time, some 2.0 exajoules, will become economic over the next 25 years; we projected productive capacity for these reserves based on the deliverability profile developed for uncontracted reserves and a connection rate of 4 percent per year.

Reserves Additions

In projecting productive capacity from reserves additions, we assumed that their producing characteristics would be similar to those of reserves added in the late 1970s and early 1980s. Reserves additions were assumed to be connected at variable rates, more slowly in the early years when excess productive capacity exists.

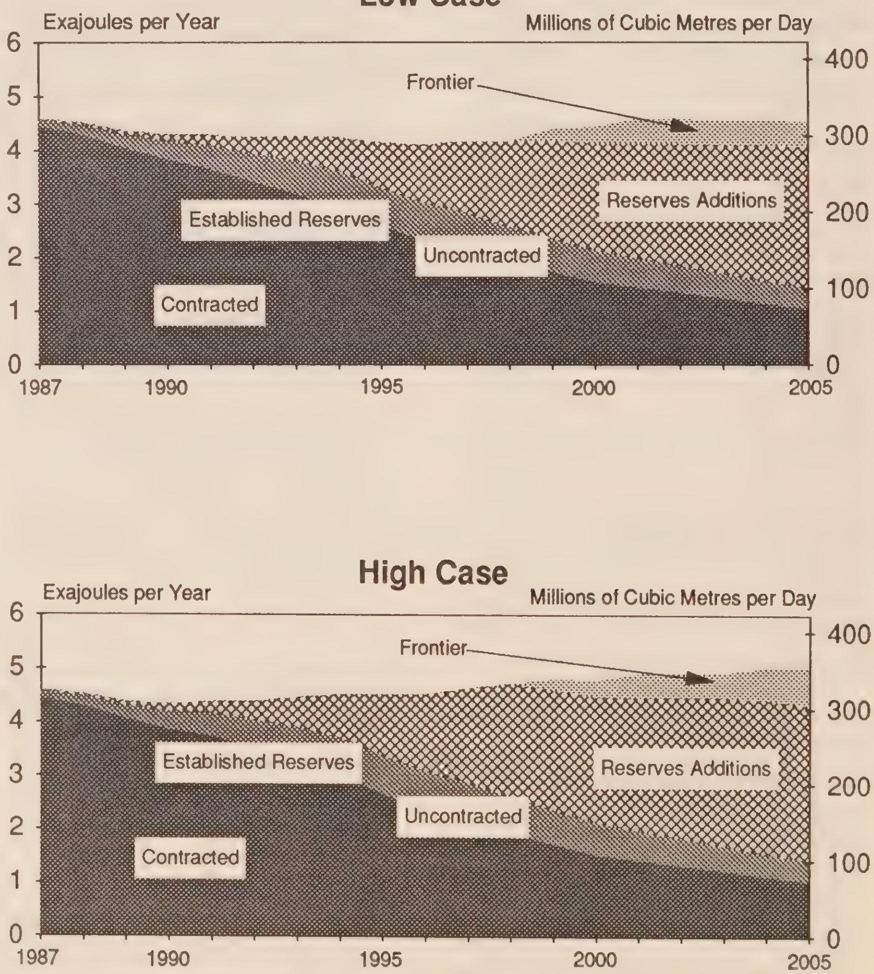
Frontier

Our projections of productive capacity for the frontier regions reflect anticipated levels of production for the east coast Venture gas project and project proposals for Mackenzie Delta gas. For the former, we assumed multi-field development would occur, with production starting at 125 petajoules, increasing to 250 petajoules in the second year and remaining constant thereafter. For the Mackenzie Delta area, we assumed an initial production rate of 200 petajoules per year increasing to a maximum rate of 450 petajoules by the third year of production. Our projections of market conditions and prices result in the production of Mackenzie Delta gas commencing in 1999 for both the low and high cases and that of Venture gas commencing in 2004, in the high case only.

Summary

Projected productive capacity from all reserves in the conventional areas is similar in the two cases. This is because our gas market analysis was conducted so as to maintain a balance between supply and demand, and there is not a large difference between our domestic and export demand estimates in the two cases. Any differences in our projections of productive capacity in the two cases result largely from the slightly different profiles of reserves additions.

Figure 6-7
Productive Capacity of Natural Gas by Supply Source
Low Case



Source : Appendix Table A6-8.

In both cases, our projections of productive capacity from established reserves currently under contract start at about 4.5 exajoules in 1987 and decline to 1.0 exajoules in 2005. When we include those reserves not as yet contracted, our projections of productive capacity are marginally higher declining to 1.4 exajoules by 2005.

Our projection of total productive capacity for the conventional areas, including reserves additions, remains in the low case between 4.3 and 4.5 exajoules per year until the mid-1990s, declining thereafter to about 4.1 exajoules at the end of the projection period. In the high case our projection is slightly higher, remaining between 4.4 and 4.7 exajoules per year until the late 1990s, declining to about 4.3 exajoules in the year 2005.

Including frontier supply, productive capacity is 4.5 exajoules by 2005 in the low case and 5.0 exajoules in the high case.

Figure 6-7 illustrates the productive capacity of natural gas by supply source for each of the two cases. Detailed projections of productive capacity are in Appendix Tables A6-6 through A6-8.

6.5 Exports

Our approach to projecting natural gas exports in this report differs considerably from previous practice. In the October 1986 Report we based the outlook for exports to 1990 on our analysis of the structure of our natural gas export trade, the U.S. regulatory environment, and regional market considerations. Beyond 1990 the outlook for exports was based on judgement about the volumes likely to flow under then-existing licences.

In this report, we are not limiting our outlook to exports under existing licences. This is for two reasons. First, exports under short-term orders have grown in importance; in 1987, almost one-quarter of our exports were made under short-term orders which are issued without limitation as to volume for a period of up to 24 months. Secondly, regulation of long-term natural gas exports is now based on the fundamental premise that exports will be market-determined provided that the market is satisfying Canadian energy needs fairly and efficiently.[1]

Hence, it has become essential to make projections of natural gas exports based on an understanding of how the marketplace would determine gas flows between the producing and consuming regions of North America.[2]

To make our natural gas export projections, we combined our knowledge of current export arrangements with a projection framework capable of assessing inter-regional gas flows in North America over a long period of time. Many factors will influence exports, the main ones being Canadian gas supply and domestic demand, U.S. domestic gas supply and demand, natural gas prices, competing energy prices, competing gas costs from various regions in both countries, and transportation costs from wellhead to market.

This section describes first the history and structure of the export trade, followed by the U.S. regula-

1. Regulation of export prices has been relaxed in a series of stages since 1983.

With respect to the regulation of export volumes, the Board in July 1987, adopted a new "Market-Based Procedure" for granting new export licences based on the premise that the market-place will generally operate in such a way that Canadian requirements for natural gas will be met at competitive market prices. The Board acts in two ways to satisfy itself that natural gas licensed for export is surplus to reasonably foreseeable Canadian requirements: one is in the context of public hearings to consider export licence applications; the other is by monitoring Canadian energy markets on an ongoing basis.

There are three components to the public hearings part of the Market-Based Procedure:

The first is a complaints procedure; the Board considers complaints that Canadian users cannot obtain additional supplies of gas under contract on terms and conditions, including price, similar to those in the export proposal.

The second is an export impact assessment; applicants for export licences are required to file an impact assessment which would allow the Board to determine whether a proposed export was likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

In the third the Board considers all other factors such as: the nature of the contractual arrangements; support by producers for the proposed export; recovery of the costs incurred; evidence that the export price is not less than the price to Canadians; availability of pipeline space; and evidence that the export was likely to result in net benefits to Canada.

As part of its monitoring process the Board will continue to publish at intervals of approximately two years its assessment: Canadian Energy Supply and Demand.

The Board also plans to periodically publish reports analyzing in more detail natural gas supply, demand and prices.

2. Our projections of natural gas exports do not anticipate future Board decisions on export or facilities applications. These decisions will be made case by case on the merits of each application under the circumstances perceived at that time.

tory environment. Then, our projections of exports are discussed.

6.5.1 History and Structure of the Natural Gas Export Trade

Since the 1950s, Canada has been a significant supplier of natural gas to the United States. Throughout the 1970s export volumes averaged 27 billion cubic metres (950 Bcf), close to levels authorized by the Board. In the early 1980s the NEB authorized large new export volumes, but for various reasons, including the 1982 recession and a high export price for Canadian gas, volumes flowing declined from 28.3 billion cubic meters (1000 Bcf) in 1979 to 20.2 billion cubic meters (715 Bcf) in 1983. Since 1983, export price regulation has been progressively relaxed and natural gas exports have rebounded to 28.0 billion cubic meters (990 Bcf) in 1987 (Figure 6-8).

Historically, export arrangements have been between Canadian transmission companies and U.S. interstate pipelines which purchase gas under long-term contracts for resale to distribution utilities along their systems. Notable exceptions to this general rule are long-term, direct sales (sales between producers and either distribution utilities or end users with the pipeline acting only as a transporter) by Alberta & Southern Gas Company Limited (A&S) and Pan-Alberta Gas Limited (Pan-Alberta) to California utilities (Pacific Gas and Electric, and Southern California Gas Company respectively), and TransCanada PipeLines Limited's (TransCanada) sale to Boundary Gas Incorporated (a group of northeastern U.S. utilities).

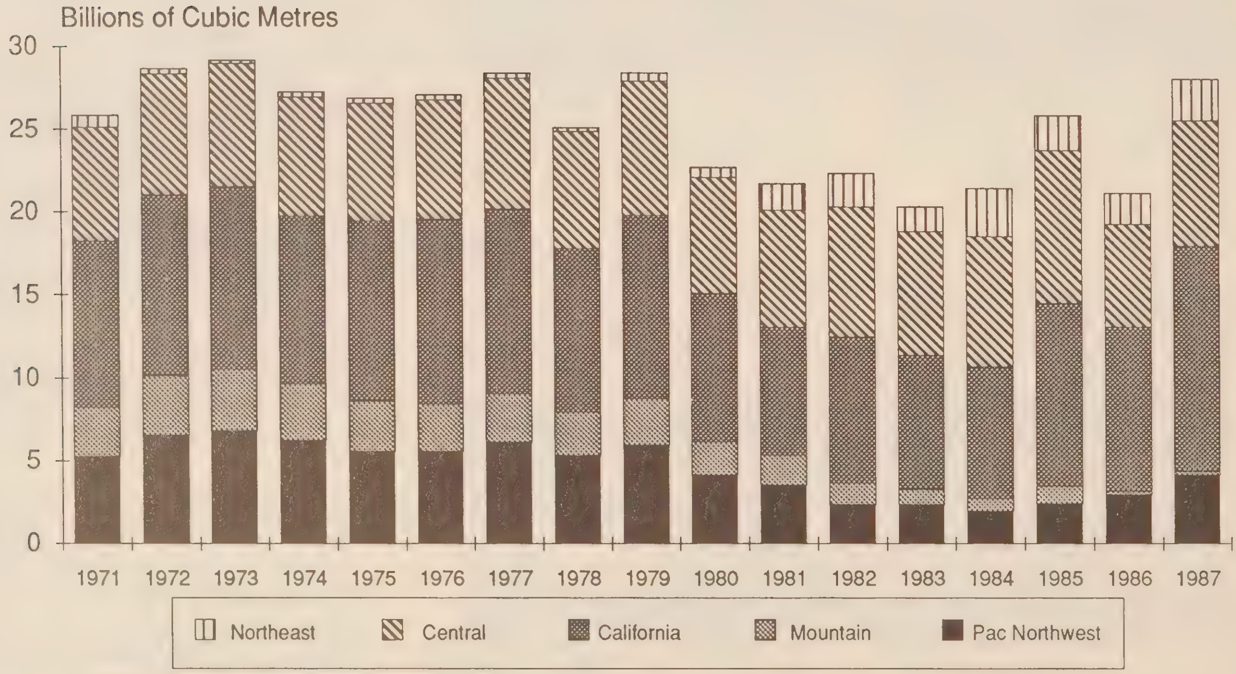
The U.S. natural gas market has undergone radical transformation over the past several years. From a market dominated by large interstate pipelines who bought, transported and sold gas to local distribution companies under long-term, inflexible contracts, there are now many buyers and sellers with an array of sales arrangements designed to meet specific needs.

In response, Canadian exporters have modified their sales arrangements to reflect the new market reality in the U.S.:

- Flexible pricing based on alternate fuel prices with regular price

Figure 6 - 8

Natural Gas Exports



Source: Appendix Table A6-9

reviews was introduced to long-term contracts.

- "Multi-tier" contracts were introduced which permitted the sale of some volumes into the spot market under a system of monthly price review.

- Marketing efforts were redirected away from system sales to pipelines to direct sales to distribution utilities.

- Short-term export sales, which were negligible prior to 1985, increased to approximately 22 percent of exports by 1987, but were still restricted by the reluctance of most U.S. pipelines to carry gas for others which could displace their own sales. This situation, however, is quickly improving.

The trend toward more shorter-term sales and direct sales in Canada's gas export trade is expected to accelerate, particularly now that the majority of U.S. interstate natural gas pipelines are open access transporters under FERC Order 500.

6.5.2 U.S. Regulatory Environment

Canada's ability to compete in U.S. markets is affected by the regulatory environment in the U.S. as well as in Canada.

The main interest to Canada in American natural gas regulation is in how it affects:

- access for Canadian gas to U.S. pipelines;

- the competitiveness of Canadian gas sold in the U.S.; and

- the netbacks to producers from export sales.

Regulation of the natural gas industry in the United States is effected through the Economic Regulatory Administration (ERA), the Federal Energy Regulatory Commission (FERC) and state public utility commissions (PUCs).

The ERA, under the direction of the Secretary of Energy, is responsible for approving exports from and imports into the United States. In early 1984, the Secretary of Energy issued new policy guidelines for the approval of natural gas imports which shifted the focus from price, national need and impact on the balance of payments to an overall test of competitiveness in the markets served. The essence of the new import policy was that import arrangements which were freely negotiated between buyers and sellers would be regarded as being competitive and therefore acceptable for import approval purposes.

The FERC is responsible for the regulation of all interstate trade in natural gas. It regulates the tolls and tariffs of interstate pipelines, approves the construction of new facilities and administers prices for some U.S. gas which is still subject to price controls. Its regulatory activities have great influence on all interstate and international gas flows.

The state PUCs approve utilities' gas purchase contracts. In many states they can have an influence on Canadian gas exports. Because Canadian gas is generally competitively priced, Canadian exports have not been adversely affected by PUC regulatory activities.

As noted, the U.S. natural gas industry has been experiencing a transformation from one dominated by pipelines which purchase gas and resell it to local distribution companies to one of open competition for markets. The FERC has played a key role in this process by encouraging pipelines to separate their transportation and sales functions and to open their systems to more transportation of customer-owned gas under Order 500. This and other regulatory developments such as FERC's Opinion 256 regarding the treatment in U.S. pipeline rates of imported gas costs, have had an important impact on Canadian exports.

As transportation of customer-owned gas started to increase in the mid-1980s, the FERC became concerned that access to pipeline capacity in the U.S. was not being made available to all shippers on a non-discriminatory basis. To address this concern, the FERC, in 1985 promulgated Order 436 which required that pipelines choosing to transport gas for others make their systems available to all users on a non-discriminatory or "open access" basis. Order 500 in 1987 refined this program by permitting the crediting of transportation volumes against a pipeline's take-or-pay liabilities and allowed for a special "gas inventory holding charge" in pipeline tariffs to mitigate the take-or-pay problems facing many U.S. pipelines. This appears to have had a beneficial impact in terms of making the program more palatable to the pipelines, although producers are generally thought to be displeased with the treatment of the take-or-pay problem.

While pipelines were initially slow to take up the challenge of open access transportation, many of the

major systems have now accepted Order 500 certificates or are in the final stages of negotiating acceptance terms.[1]

Initially, these U.S. events adversely affected Canada in two ways:

- Canadian exporters were being denied access to U.S. pipelines for the purpose of making direct sales to U.S. customers, and U.S. pipelines were reducing their own purchases of Canadian gas in favour of indigenous gas in order to lower their take-or-pay exposure to American producers (take-or-pay levels had been generally lowered or removed from Canadian contracts). This situation, however, is quickly improving as more pipelines become open access systems providing transportation service.

- Some U.S. pipeline companies, in applying for open access status, also proposed that their tolls for transporting gas be based on large geographic zones rather than on distance as had been proposed by FERC in Order 436. For example, Northern Natural Gas Co., in applying for open access, proposed to create two separate rate zones, a field zone and a market zone. The transportation charge within the field zone would be based on distance whereas the charge in the market zone would be a "postage stamp" rate (a single rate for transportation irrespective of distance). Canadian exporters argued that the use of a postage stamp rate within the market zone discriminates against Canadian gas which enters Northern's system at points near the major load centres whereas U.S. producers must move their gas across longer distances to reach the same load centres but are charged the same rate. None the less FERC has upheld the concept of rate zones.

On 4 April 1988, the FERC issued a notice of proposed rulemaking regarding brokering of firm transportation rights on interstate pipelines which have accepted Order 500 and are open carriers. This is a new issue before the Commission; final regulations regarding brokering will take time to establish. The Commission stated that there are potential benefits from a properly structured brokering program, including a more efficient allocation of unused firm capacity leading to reduced costs and increased throughput, incentives to utilize alternative peak period transportation, and flexibility to adjust to market conditions. From the Canadian perspective, it is unclear at this time what impact brokering will have on natural gas exports.

U.S. pipeline rate regulations can also affect the competitiveness of Canadian gas. The most recent example is FERC Opinion 256 issued in December 1986 which addressed the structure of "demand" and "commodity"[2] charges for Canadian gas. The issue is whether U.S. importers should be allowed to pass on to customers, costs of imported gas on an "as billed" basis, specifically, whether the full demand charge included in Canadian exports should be permitted to be included as part of the demand charge component of importing companies' sales rates to their customers. The FERC ruled that the structure of import prices to be reflected in pipeline sales rates should be the same as that used in pricing U.S. gas notwithstanding that the ERA had approved the import contract concerned.

The structure of U.S. domestic pipelines sales rates is, for the most part, based on FERC's "modified fixed/variable"[3] cost methodology. This ruling required that certain cost elements (relating to Canadian production and gathering costs and return on equity) which had been included in the demand charge, be removed from the U.S. pipelines' demand charge and added to the commodity charge.

The effect of the FERC decision is to put the importing pipeline at risk for under-recovery of those costs which are included in the demand charge of the Canadian exporting company but which are shifted, by Opinion 256, to the commodity portion of the importing pipelines' sales rate. As a consequence, imported gas becomes less competitive with U.S. domestic gas because of the enlarged commodity portion of the two-part rate charged by a U.S. pipeline.

While importing pipelines could choose to accept the risk of under-recovery of export contract

1. At the time of writing some 16 major pipelines which, in total, carry about sixty percent of all the gas carried on the U.S. interstate pipeline system, have accepted certificates.
2. *A demand charge* is a fixed, usually monthly obligation of a gas purchaser in a sales contract. It may cover some or all of a seller's fixed costs and is payable regardless of volumes actually taken.
A commodity charge is a charge payable by a gas purchaser in a sales contract for each unit of gas purchased. The unit charge generally covers the commodity component of the applicable pipeline toll and the cost of gas, and may include a portion of the fixed costs of the seller.
3. Under the modified fixed/variable method, all variable costs together with the return on equity and related income taxes are assigned to the commodity component of rates. Fixed costs are assigned to the demand component of rates.

demand charges, in fact they have sought to renegotiate their import purchase contracts to move cost elements from the demand charge to the commodity charge, consistent with Opinion 256. This shifts the risk of under-recovery to the Canadian exporter and adds to the financial risk for Canadian producers.

Exporters have reacted to Opinion 256 by altering the structure of their sales arrangements. In one case, an exporter added a provision to the sales contract permitting renegotiation of the terms of the sale in the event that the quantity sold were to fall below the minimum level needed for recovery of all Canadian costs; others have sought to convert sales presently made to pipelines to sales made directly to the pipelines' customers because such direct sales are not subject to the FERC ruling.

In other regulatory developments, FERC issued Order 451 in June 1986 and repealed the U.S. Powerplant and Industrial Fuel Use Act in May 1987. Order 451 replaced a myriad of ceiling prices for so-called "old" natural gas (low cost gas still subject to price regulation) with a single national ceiling price of $U.S. 2.57 per million Btu, to be adjusted for inflation. The intent of the order was to remove inflexibility in gas pricing and improve the economics of gas production from older pools. This initiative, however, has not met with great success, as the order required producers who wished to avail themselves of the higher price for old gas to bring their high priced "new" gas contracts to the bargaining table as well. The U.S. Powerplant and Industrial Fuel Use Act, which had prohibited new electricity generating plants and large industrial boilers from consuming oil or natural gas as a primary fuel source, had been designed to reduce petroleum and natural gas consumption and to encourage greater use in these applications of alternative fuels such as coal. The repeal of this Act has resulted in increased demand for Canadian natural gas in new power generation projects. In fact, several export applications are anticipated for natural gas use in power generation facilities.

It is apparent that the American regulatory environment is becoming more open as evidenced by the number of pipelines which have accepted open access, by the increase in Canadian natural gas exports since early 1987, and by the multitude of alternatives to the traditional long-term contract supply services which are available to suppliers of gas and their purchasers. In this new environment, Canadian exporters will have to respond quickly to changing market conditions by continuing to provide an array of competitively priced sales services, both long- and short-term, using both direct sales to local distribution companies and end users as well as the traditional sales to pipelines for their system supply.

6.5.3 Export Projections

In a market-oriented trading environment, the main factors affecting natural gas exports to the U.S. over the long term include:

- comparative wellhead supply costs between the two countries,
- interfuel competition, especially between fuel oil and natural gas,
- transmission charges from Canadian wellheads to U.S. markets relative to U.S. transmission charges from U.S. wellheads to U.S. markets,
- the size of the U.S. market for natural gas,
- the level of Canadian natural gas supply and demand, and
- any regulatory or other governmental measures which discriminate between Canadian and U.S. gas.

Generally we expect that Canadian exports would be greater:

- the lower our wellhead supply costs,
- the higher the fuel oil price,
- the lower the transmission charges affecting exports to U.S. markets,
- the higher the transmission charges affecting U.S. internal supply,
- the larger the size of the U.S. gas market,
- the lower the level of Canadian gas demand, and
- the higher the level of Canadian gas supply.

To make these estimates, we used an analytical framework[1] which takes into account the individual character of many supply sources, regional markets, transportation alternatives and producer and consumer behaviour. It has a detailed representation of regional supply, demand and interregional transportation linkages to serve the purpose of working out plausible

1. "North American Regional Gas Model", property of Decision Focus Inc., Los Altos, California.

long-term export projections. This framework estimates demand, and at each point in the supply chain where gas supplies can compete with each other or with oil, it selects and routes volumes in order to minimize costs to consumers and maximize returns to resource owners; resource owners make gas available taking account of the long-term value of gas. It is assumed that resource owners expect the oil price and gas cost profiles used in the analysis, and it calculates the user-cost[1], which is recovered in the price, from each source. The model balances the market at five-year intervals beginning in 1987.

Figure 6-9 shows the demand regions, supply regions and transportation linkages forming the structure of this analytical framework.

This framework is one of a number which could be used for making natural gas export projections. Export estimates could vary substantially, depending upon the model used and assumptions made about the key factors which influence export flows. A good indication of this variability comes from a forthcoming Energy Modeling Forum (EMF) study on North American natural gas markets.[2] For most models used in that study, total gas imports to the U.S. (including small volumes of LNG and Mexican supply) range between 0.3 and 1.8 Tcf in 1990 and 0.4 to 2.8 Tcf in 2000. The minimum values occur in two analyses of the Low Oil Price scenario, while the maximum values occur in two other analyses of the "Low U.S. Gas Resource" case. Our results, shown in Table 6-8, fall within this range, but are well below the maximum U.S. imports which these alternative projections indicate.

Our projections are based on modest growth in U.S. demand, which reflects major elements of the GRI Baseline Projection for 1987-2010, December 1987.[3] If U.S. gas demand were to grow by much more than that of the GRI projection, U.S. demand for Canadian gas could well be greater than our projections indicate. Hence, it is well to outline the main considerations underlying the modest U.S. demand growth in the GRI Baseline Projection.

According to this projection, U.S. primary consumption of natural gas grows slowly at about 0.8 percent per year between 1986 and 2000, and at 0.2 percent per year between 2000 and 2010. The corresponding growth rates for total energy use are 1 percent per year in both periods. Natural gas loses market share to coal, electricity, renewables, and petroleum - though to a very small extent in the case of petroleum.

GRI's projection of modest energy demand growth is based on continuing efficiency improvements in energy use and restructuring of the economy into less energy-intensive activities.

Up to 1990, industrial gas consumption increases, but part of the increase is offset by a projected decline in electric utility gas consumption. Much of the growth between 1990 and 2000 is the result of increased demand by electric utilities, and for commercial cogeneration and cooling services. There is little growth in gas use in the residential and commercial sectors.

Residential gas demand goes down over the long term because efficiency improvements in heating equipment and improved thermal integrity of housing more than offset the projected increase in gas heated homes.

GRI sees commercial gas use growing most noticeably in the South and West regions, where space cooling will create a large market for gas-based cooling equipment and cogeneration.

GRI projects industrial gas use to grow by only 0.4 percent per year between 1986 and 2010. The continued restructuring of the industrial sector will have a larger proportional impact on industrial gas consumption than on other fuels due to the larger share of industrial gas consumption in declining industries.

GRI makes the point that gas will face tough price competition from fuel oil, coal and waste in the industrial market.

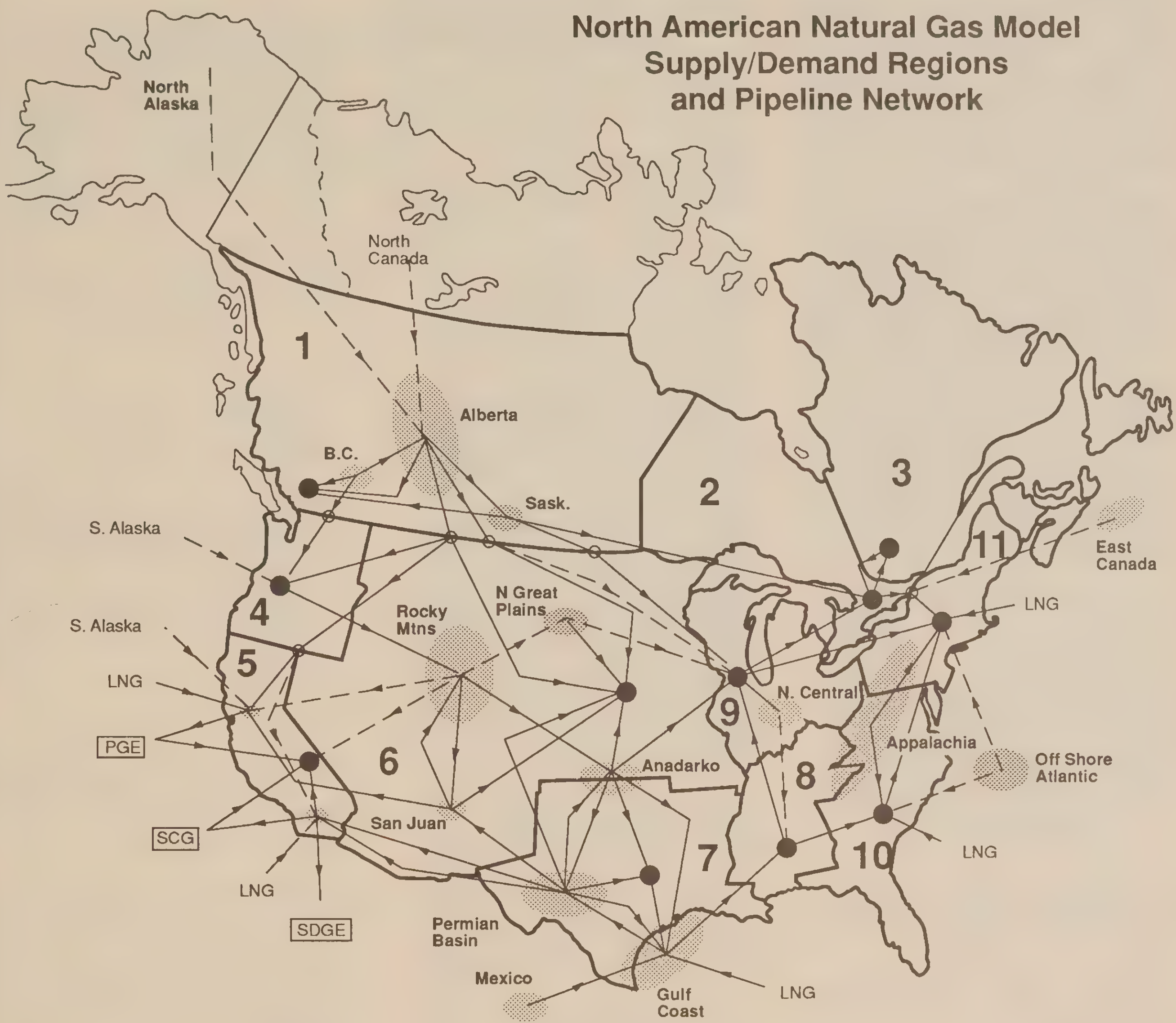
In our projections, U.S. gas consumption grows in the high case from 16.2 Tcf in 1987 to 18.2 Tcf by 1997, then falls back to 17.3 Tcf by 2007. In the low case it hovers about 17 Tcf from 1992 to 2002 and falls to 16.2 Tcf by 2007. U.S. gas consumption estimates in the EMF study range between 14 and 21 Tcf in the post-2000 time period, going from the "low oil price" to the "high demand" scenarios respectively.

For Canadian natural gas supply, we used the resource estimates and gas supply costs described in

1. The concept of the "user cost" is explained in Section 3.1.
2. *North American Natural Gas Markets: EMF-9 Summary Report*, Energy Modeling Forum, Stanford University, Stanford, California
3. P.D. Holtberg, T.J. Woods, and A.B. Ashby, *1987 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, Gas Research Institute, Chicago, Illinois, 1987.

Figure 6-9

North American Natural Gas Model Supply/Demand Regions and Pipeline Network



Legend

- Demand Regions
  1. Western Canada
  2. Ontario
  3. Eastern Canada
  4. Pacific Northwest
  5. California
  6. Central
  7. Southwest
  8. East South Central
  9. East North Central
  10. South Atlantic
  11. Mid and NE Atlantic
- Supply Regions
- Active Pipelines
- Potential Pipelines
- Border Crossings

Source: Decision Focus Incorporated

previous sections of this chapter. The basis of the U.S. supply projection is a potential for the Lower 48 states of 550 Tcf over and above the 160 Tcf of existing reserves. The U.S. Potential Gas Committee's 1986 minimum and most likely estimates of technical potential are about 400 and 600 Tcf respectively.

We used DFI's cost estimates for the various U.S. supply categories identified in the framework, adjusted to reflect the differences in gas supply costs between the low and high cases. Over the study period, "Lower 48 deep gas" grows from about 8 percent to 30 percent of U.S. supply. If this were an over-estimate of the competitiveness of U.S. deep gas, Canadian exports could be greater than our results indicate.

For U.S. transportation rates, we adopted DFI's rates developed for the pipeline network in Figure 6-9; for Canadian transportation rates, we provided estimates based on our most recent information, with an assumed annual reduction of TOPGAS carrying charges to the end of the program in 1994.

Our analysis incorporating all of these factors results in the export projections of Table 6-8.

The most interesting features of our results are that:

- exports grow rapidly in both scenarios between 1987 and 1992; thereafter they are stable;
- Canada's share of the U.S. market grows from its 1987 level of approximately 6 percent to about 8 percent, and
- there is virtually no difference in export volumes between the two scenarios.

Table 6 - 8

Exports of Canadian Natural Gas to the U.S.

Year [a]	Low Case (Billions of Cubic Metres)	Low Case (Bcf)	High Case (Billions of Cubic Metres)	High Case (Bcf)
1987	28	990	28	990
1992	39	1375	41	1440
1997	39	1370	41	1430
2002	39	1390	39	1390
2007	39	1360	39	1360

Note: [a] These are the years for which the model we used estimates results.

The large increase of Canadian gas exports and of Canada's market share between 1987 and 1992 happens mainly because of differences in incremental cost profiles between Canadian and U.S. supply sources. In the early part of the study period it costs less to supply incremental amounts of Canadian than U.S. gas. This happens because generally Canadian sources begin with a higher ratio of reserves to production than do U.S. sources. Therefore, U.S. suppliers incur incremental costs associated with adding reserves sooner than do Canadian suppliers. Another factor is that in 1987 some trade may have been frustrated by pipeline access problems. Exports for 1988 may be about 36.8 billion cubic metres (1.3 Tcf), an increase of 31 percent over the 1987 level. This suggests the possibility that 1987 exports were below the volumes which may have occurred in a more open market environment.

The stability of exports and Canada's market share after 1992 happens largely for two reasons:

- The size of the U.S. market fluctuates within a narrow range around 462 to 510 billion cubic metres (16.3 to 18 Tcf).
- From the mid-1990s onward, generally, Canadian sources do not enjoy incremental cost advantages relative to U.S. sources, hence there is very limited scope for incremental market penetration.

If the U.S. resource were less abundant and costlier to find and develop than assumed in our work, Canadian exports would most likely exceed our projections.

The virtual sameness of Canadian natural gas exports between our Low and High scenarios happens because we have postulated a substantial decrease in the cost of finding and developing natural gas supply in the Low scenario relative to that in the High. The consequence of this assumption is that natural gas markets in both countries remain much larger than they would have been had we not allowed the cost of gas to adjust to the low oil price energy market which characterizes the Low scenario. Without this adjustment, U.S. and Canadian gas would have lost a substantial portion of the fuel-switchable market to oil, caus-

ing low case Canadian exports to be in the range of 28 billion cubic metres (1 Tcf) or less.

There is a wide range of views on future Canadian gas exports to the U.S. For the year 2000, published views range from about one-half to two and a half Tcf (see inset table); most analysts expect Canada to be the primary source of U.S. gas imports.

Natural Gas Exports Range of Views

	(Bcf) Year 2000
CERI	
High	2000
Low	640
The WEFA Group	1900
DRI	1831
EIA	2500
GRI	1600
EM&R	1500
EMF	
High	2000
Low	500

Legend:

CERI = Canadian Energy Research Institute, February 1988, Study No. 26, p. 18.

The WEFA Group = Energy, Metals and Minerals, The WEFA Group U.S. Energy Forecast, Summer 1988 p. 7.81.

DR = Data Resources Energy Review, Summer 1988, Volume 12, Number 2 p. 65.

EIA = Energy Information Administration, Annual Energy Outlook 1987, Table A9.

GRI = Gas Research Insights, 1988 Baseline Projection of U.S. Energy Supply and Demand to 2010.

EM&R = Energy, Mines and Resources Canada.

EMF = North American Natural Gas Markets: EMF 9 Summary Report, Energy Modelling Forum, Stanford University, Stanford, California, forthcoming.

Regional Markets

The composition of these exports by U.S. demand region is shown in Table 6-9.

There are a number of interesting features of the regional results:

- The regional composition of exports remains stable over time.
- The Central area (a composite of four U.S. gas demand regions) and California remain Canada's most important export destinations over the study period in both scenarios; together they account for over 70% of our exports.
- In 1987 California was the largest export destination; however, from 1992 onward, the Central area and California are of similar importance. This change most likely reflects the difficult pipeline access and more intense competition which characterized the Central area in 1987.
- The North-East region grows in importance from about 9 percent of exports in 1987 to 13 percent from 1992 onward. Exports to the Pacific North West region increase appreciably by the early 1990s.
- Canada's exports to the Central region grow considerably between 1987 and 1992; however, Canada's share of total gas consumption in this market is about 4 percent to 5 percent from 1992 onward in both cases.

Pacific Northwest

In 1987, some 65 percent of the natural gas consumed in the Pacific Northwest region of the United States originated in Canada, primarily British Columbia. The main Canadian exporter to this region is Westcoast and the principal U.S. buyer is Northwest Pipeline Corporation (Northwest). Westcoast also exports gas from Alberta through the pipeline facilities, in Canada, of Alberta Natural Gas Company Limited (ANG) and, in the United States, of Pacific Gas Transmission Company (PGT) which interconnects with Northwest. As well, a number of other companies, mainly producers, export gas to this region.

During the early part of the decade, exports to this market declined substantially as a result of the recession and competition from electricity and residual oil. Current low prices for residual oil make this a difficult market for natural gas to penetrate.

The capacity of Northwest to deliver indigenous natural gas into the region is limited as it is at the end of the Northwest system. Consequently, Canadian gas in this market is less susceptible to competition from low cost U.S. gas but is still subject to competition from high sulphur residual fuel oil. To retain and expand its share of the market, Canadian gas will have to be competitively priced with residual fuel oil, particularly now that Northwest is an open access carrier under FERC Order 500.

Because of proximity to the market and the presence of ample Canadian pipeline capacity, Canadian exporters are well positioned to serve this market. Our expectation is that Canadian gas will increase to about 88 percent of this market by 1992, with annual sales of approximately 6 billion cubic metres (215 Bcf).

Table 6 - 9

Composition of Canadian Natural Gas Exports By U.S. Demand Regions

Billions of Cubic Feet

Low Case

REGIONS	PNW	%[a]	CAL	%[a]	CTR	%[a]	NE	%[a]	TOTAL	%[a]
1987	151.8	65	478.0	28	269.7	2	90	4	989.2	6
1992	214.0	88	506.0	27	482.0	4	173	9	1375.0	8
1997	213.0	88	492.0	25	487.0	4	176	9	1368.0	8
2002	216.0	88	488.0	24	512.0	5	175	9	1391.0	8
2007	217.0	88	482.0	24	486.0	5	176	10	1361.0	8

High Case

REGIONS	PNW	%[a]	CAL	%[a]	CTR	%[a]	NE	%[a]	TOTAL	%[a]
1987	151.8	65	478.0	28	269.7	2	90	4	989.2	6
1992	211.0	88	500.0	27	549.0	5	182	8	1442.0	8
1997	218.0	88	491.0	23	539.0	5	183	8	1431.0	8
2002	223.0	88	489.0	23	504.0	4	174	8	1390.0	8
2007	227.0	88	488.0	23	466.0	4	180	9	1361.0	8

Note: [a] Percent is Canadian Supply as a percentage of regional U.S. natural gas consumption.

Legend: PNW = Pacific Northwest and Mountain Demand Regions
CAL = California
CTR = West North Central, West South Central, East North Central and East South Central Demand Regions
NE = New England, New York and Mid Atlantic Demand Regions

California

California is the largest single market for Canadian natural gas exports, accounting for approximately one-half of exports in 1987. Canadian gas, produced for the most part in Alberta, supplies about one-quarter of the gas consumed in California.

The largest Canadian exporter is A&S and the U.S. importer is PGT. The ultimate buyer of the gas is Pacific Gas and Electric Company (PG&E), a major San Francisco-based utility serving the northern half of the state and the owner of A&S and PGT.

Pan-Alberta exports large quantities via the western leg of the Foothills system. The routing of this export starts with Foothills Pipeline (Yukon) Limited and Nova, An Alberta Corporation. It next enters the ANG system and moves from there to the PGT system (as do Westcoast and A&S volumes). The gas continues in the PGT system to the Northwest system, where by displacement equivalent volumes are made available to El Paso Natural Gas Company (El Paso) for subsequent delivery to Southern California Gas Company (SoCal). Pan-Alberta's exports to this market have been at authorized levels for more than three years. Westcoast and several producing companies have become active in the California spot market over the past year.

The demand for natural gas in California, which had declined in recent years because of an abundance of hydroelectric power and the start up of the Diablo Canyon and San Onofre nuclear plants, appears now to have stabilized and

is expected to increase moderately during the forecast period.

The primary competition to Canadian gas in both northern and southern California is U.S. spot gas and system gas supplied by El Paso,mainly from Texas and New Mexico. El Paso sells its own gas to SoCal and PG&E under long-term contracts and transports gas for other producers selling to the two utilities through a monthly spot market bidding system. In addition to selling gas under long-term contracts, Canadian exporters have been active participants in the monthly spot market and have been able to maintain their share of the market despite stiff competition. Also, there are indications that PGT will become an open access carrier under Order 500. This should enhance the access of short-term Canadian gas to this major market during periods of excess capacity.

California is expected to remain one of Canada's most important export destinations because the conditions which caused it to become so in the past are expected to continue over the study period. Canada suffers less of a transportation cost disadvantage serving the California market than it does serving certain Central and Eastern U.S. markets, according to the pipeline transportation charges assumed in the gas flow analysis. Hence California is the U.S. market most within Canada's economic reach.

The major resources closest to California are from the Western Canada, Anadarko and Permian basins. The growth rate of supply costs per incremental unit of reserves additions does not differ substantially among these three regions over our study period. Hence, Canada's market share does not grow.

There is an alternative view of Canada's role in the California market, according to which, over the long run, Canada's market share should grow by more than our projections indicate. Which view will be closer to reality depends upon which prognosis one adopts for future gas supply within the U.S. In the portrayal of the U.S. gas resource we have adopted, (based on U.S. Potential Gas Committee estimates), Permian, Anadarko and Rocky Mountain supply shows more growth relative to Gulf Coast supply than may happen according to another view of U.S. regional resource potential. The Gulf Coast is farther from California than are the Permian and Anadarko basins. The lower the prospects for the proximate sources relative to the more distant ones, the better the prospects for Canadian natural gas in that market.

It is also possible that volumes will increase if any of the pipelines proposed to serve the enhanced oil recovery (EOR) projects in central California were constructed or if PGT were to proceed with a planned expansion of its pipeline from Canada.

Central Region

The Central region is the largest U.S. natural gas consuming region and is our second largest market, accounting for 27 percent of exports in 1987.

Although substantial volumes of Canadian gas are consumed in this region, our share of total consumption in 1987 was only about 2.5 percent. The eastern part of the region is characterized by large residential and industrial consumption. Price competition from low sulphur, residual oil is intense in the industrial sector. The western part of the region has a smaller industrial load which faces competition from high sulphur residual oil and coal. Gas consumption, which had been declining in recent years, is now stabilizing due to the increased availability of competitively priced gas.

Natural gas from Alberta is exported to this region by TransCanada at Emerson, Manitoba to a number of United States pipelines: Great Lakes Gas Transmission Company, Midwestern Gas Transmission Company, ANR Pipeline Company and Natural Gas Pipeline Company of America as well as to several distribution utilities. Exports at Monchy, Saskatchewan by Pan-Alberta via the Eastern Leg of the Foothills system to Northern Border Pipeline Company are delivered directly or by exchange to three U.S. pipelines: Northern Natural Gas Company, Panhandle Eastern Pipeline Company and United Gas Pipeline Company. Canadian gas is also sold through Emerson and Monchy by Consolidated Natural Gas Limited and ProGas Limited. Gas started to be sold into the U.S. spot market in July 1987 under an arrangement whereby United agreed to release its unused firm pipeline capacity on Northern Border and on its own system for use by Pan-Alberta. Other Canadian producers have also started to participate in the spot market since December 1987 when Northern Border became an open-access system.

ICG Transmission Holdings Limited exports small volumes at Sprague, Manitoba and re-imports at Rainy River, Ontario. Gas is distributed to several Ontario communities, and the remaining volumes are then

exported at Fort Frances, Ontario to serve some small communities in northwestern Minnesota, and Boise Cascade, a pulp and paper plant at International Falls, Minnesota. Approximately one-half of this market has been lost to coal and wood in the past few years.

While the prospects for renewed market growth are limited due to the loss of industry to the southern and western states and to conservation efforts over the past decade, Canadian exports have recently rebounded, mainly as a result of Pan-Alberta's agreement with United, Northern Border's adoption of open access in December 1987 and higher takes by some pipeline customers. However, there still exists a considerable amount of excess capacity on U.S. pipelines serving the region, providing U.S. producers and marketers with a natural outlet for surplus supplies and making this region the most competitive gas market in the country.

Our outlook is for an increase in Canada's market share from 2.5 percent in 1987 to about 4 to 5 percent in 1992, with exports attaining annual levels of 14 billion and 16 billion cubic metres (480 and 550 Bcf) by 1992 in the low and high cases respectively.

Northeast Region

Although the Northeast region accounts for only 14 percent of total United States natural gas consumption, it has experienced a steadily rising demand for gas, growing by almost 30 percent in the past ten years.

Canadian gas presently accounts for only 4 percent of the natural gas consumed in this region. This is expected to grow to about 8 to 9 percent, 5 billion cubic metres (175 Bcf) annually by 1992.

Natural gas is exported to the Northeast at Niagara Falls, Ontario by Esso (under a licence formerly held by Sulpetro) to TEMCO, by TransCanada to Boundary Gas Incorporated, and by KannGaz to Tennessee Gas Pipeline Co. Some of ProGas' exports at Emerson, Manitoba reach this region through displacement arrangements with U.S. pipelines.

As well, Niagara Gas Transmission Limited exports at Cornwall, Ontario to St. Lawrence County in northern New York State and TransCanada exports to northern Vermont at Philipsburg, Quebec. These border markets are primarily residential and commercial and the load is highly temperature sensitive. The prime competition is fuel oil and to a some extent wood.

Because of its geographic position at the end of the U.S. interstate pipeline system, the Northeast generally pays more for its gas and is exposed to more frequent supply curtailments than any other region. This gas market is about two-thirds residential and commercial; the remaining one-third is exposed to competition from low cost residual oil. There is thought to be a large potential domestic heating demand which could be served with the existing distribution infrastructure but is not being served now because of the lack of firm winter supply. Also, there is a large amount of oil-fired electricity generation in this region which could be converted to gas if gas were competitively priced. As well, new electricity generation capacity will be required in the 1990s, part of which could be gas-based. However, gas in the electric utility sector is at risk to competition from oil, depending upon the future relationship between gas and oil prices, and the kind of fuel handling capacity developed.

There have been several new developments in this market region over the past two years. In 1987, the NEB approved three new export projects to serve the northeast markets. Shell Canada exports to Granite State Gas Transmission began serving the Maine and New Hampshire area late in the year with the conversion of one of the Portland-Montreal oil pipelines to natural gas service. A sale by ProGas to Ocean State Power intended to fuel a new electric generating facility in Rhode Island is expected to be in operation in 1989. Finally, the Alberta Northeast group has been granted export licences to supply gas to distribution companies serving the New England, New York and New Jersey markets through new facilities proposed to be built by Iroquois Gas Transmission System, one of the applicants in the FERC's omnibus Northeast Pipelines Project Proceeding (the so-called "open-season") concerning new gas supply proposals to serve the Northeast market.

The FERC is at the initial stage of this proceeding. It is estimated at this time that these proceedings will take some time and substantial new gas supplies are not expected to flow before the early 1990s.

In both scenarios Northeast U.S. gas consumption hardly changes over the study period. This results from two off-setting developments: the residential and commercial markets grow as discussed above, but the fuel-switchable industrial and utility markets decline from the mid-1990s onward as gas faces increasingly tough price competition from oil.

New England supply comes mainly from:

- Gulf Coast via the South Atlantic region,
- Appalachia,
- Anadarko via the East North Central region,
- LNG imports, and
- Western Canada imports via Ontario.

In both scenarios, the shares of Anadarko and Gulf Coast gas in the Northeast market decline while that of Appalachia gas increases over the study period. LNG penetration is relatively less in the low case than in the high, largely because we did not adjust LNG supply costs downward in the low scenario as we did other supply costs. Had LNG costs been reduced accordingly, it is likely that Canadian exports to this region would have been lower.

Insofar as present pipeline capacity from Canada directly into the Northeast is about 3.7 billion cubic metres (130 Bcf) per year, and our analysis suggests that the export market may grow to about 5 billion cubic metres (175 Bcf) per year or more, there is scope for additional capacity to this region. It is possible, however, that it would be more economic to serve this market indirectly from western Canada by displacement sales along the U.S. pipeline linkages. It is beyond the scope of this analysis to determine the economics of alternative transportation capacity increments. We indicate here only a potential overall requirement.

6.5.4 Summary Comments on Exports

Our natural gas export projections fall within a rather broad range of recent projections which assume the operation of a workably competitive market. The most important factor which would boost our high case exports well above our projection is a relatively higher cost, less abundant U.S. gas resource than that adopted in our work. Our low case export projection could be overstated to the extent that cost conditions in the natural gas industry were less responsive to the oil price environment than we have portrayed.

The level of exports does affect natural gas prices and demand in Canada. As exports increase, the total call on Canadian resources increases, causing the natural gas price to increase. However, the percentage increase in the price is less than the percentage increase in exports. As the price increases demand decreases, but the percentage decrease in demand is less than the percentage increase in price. In sum, a percentage increase in exports causes a much smaller percentage decrease in Canadian demand. Hence, the initial impact of small percentage changes in export estimates on Canadian energy demand may not be large. Impacts may become larger later in time when the gas resource is becoming increasingly more expensive to supply.

6.6 Concluding Comments

In this section we summarize the conclusions and highlight the implications of our analysis of North American gas markets.

As discussed in Chapter 3, we iterate between our supply and demand analyses to determine market prices for natural gas which result in a balanced market. The projections of total supply and demand which result from this procedure are shown in Figure 6-10. The total productive capacities shown have been adjusted for previously unused capacity. Total demand is subdivided into domestic and export components.

Our projections indicate that there will be an oversupply of natural gas until the early to mid-1990s, even though reserves additions remain low until that time as a consequence of relatively low gas prices. For the remainder of the projection period market forces result in an approximate balance of supply and demand. Reserves to production ratios for the Western Canada Sedimentary Basin decline from current levels of about 22 to between 11 and 12 in 2005.

In both the low and high cases, demand rises quite steadily over the projection period, while supply fluctuates slightly, because additions to productive capacity tend to be lumpier than are increments of demand; this is especially so for frontier supply. Domestic demand rises from about 2.0 exajoules per year in 1987 to 2.9 exajoules per year in the low case and 3.2 exajoules per year in the high by 2005. Exports rise from the current levels of about 1.3 exajoules per year to 1.5 exajoules per year in both the low and high cases.

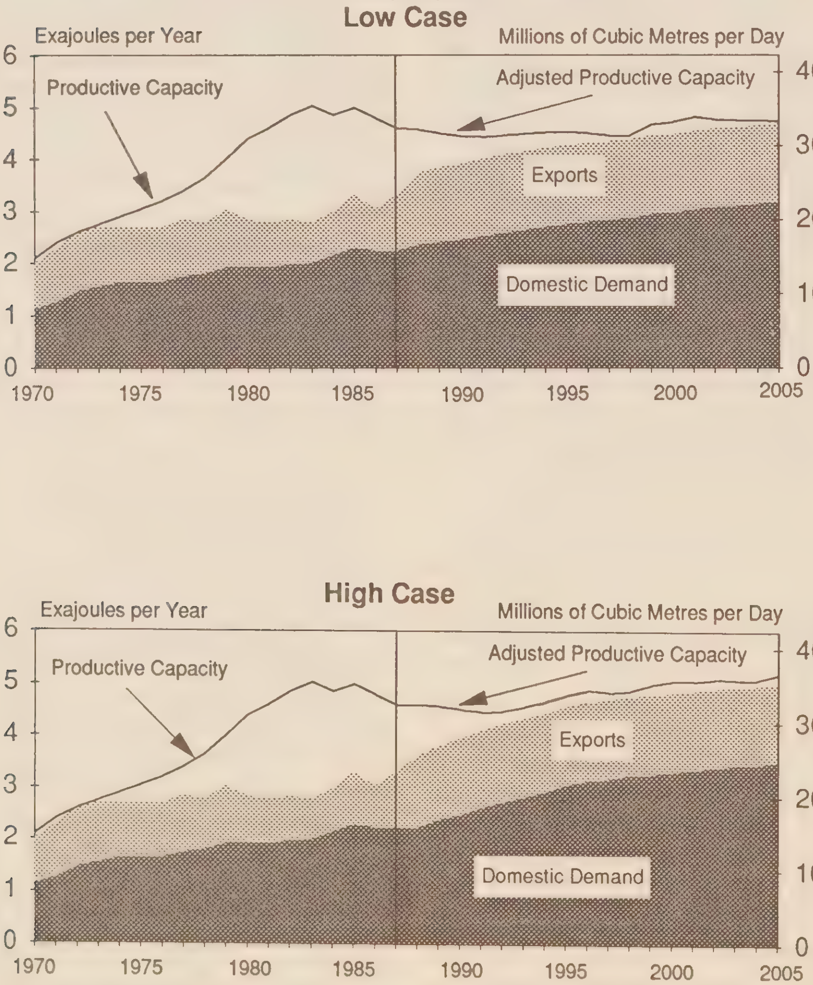
The low case projections of supply and demand are not much different from those of the high, largely because of the lower supply costs we have assumed for the low case. Oil prices in the low case rise to levels that are about 66 percent of those in the high case by 2005, while estimated natural gas costs in the low case are about 65 percent of those in the high case through the projection period. Consequently gas is about equally competitive with oil for the two cases in the later years of the projection period. Higher gas costs in the low case would reduce both

domestic and export demand and result in a greater difference in the projections for the two cases.

In Section 6.3 we conclude that the industry will be able to achieve the levels of exploratory drilling needed to maintain the total supply shown in Figure 6-10. This conclusion is based on projected costs and reserves additions rates, both of which critically depend upon the magnitude of undiscovered natural gas resources. Our projections are based on an ultimate technical potential for the Western Canada Sedimentary Basin of 225 exajoules. However, there is much uncertainty associated with this estimate of resources. Estimates by the Geological Survey of Canada (GSC) range from about 185 exajoules at high expectation to more than 300 exajoules at low expectation. WGML submitted an estimate in excess of 300 exajoules for this basin.

In our October 1986 Report we estimated the ultimate potential (economic) of the Western Canada Sedimentary Basin to be in the range of 170 to 200 exajoules, which was unchanged from the September 1984 Report. As a basis for our projections of reserves additions we then used the mean value of 185 exajoules as a constraint on the quantity of new gas that could be added to reserves during the projection period. In this report we adopt an ultimate technical potential of 225 exajoules as the basis for our projections of reserves additions (based on GSC estimates). In Section 6.3 we estimate the corresponding ultimate economic potential to be approximately 205 exajoules. Of this potential, 135 exajoules had been discovered by the end of 1986.

Figure 6-10
Natural Gas Supply and Demand



Source : Appendix Table A6-11.

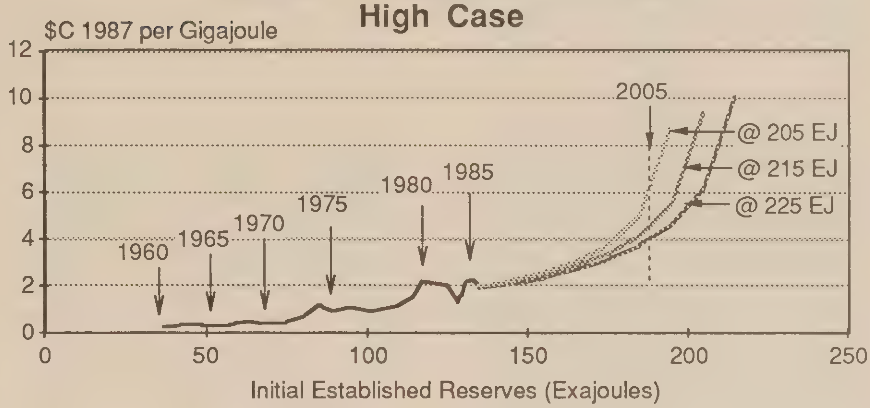
Our projection of the relationship between supply costs and resource potential of the Western Canada Sedimentary Basin is illustrated by the net[1] incremental direct cost curves shown in Figure 6-11. The three curves shown are for ultimate technical potentials of 225 exajoules, 215 exajoules and 205 exajoules, which correspond to ultimate economic potentials of approximately 205, 195 and 185 exajoules respectively. The figure shows that costs rise rapidly as the limit of the resources is reached, and that the lower the potential, the costlier the reserves additions at each level of "initial established reserves". For example, at a level of initial established reserves of 190 exajoules (approximately our projected level for 2005), the net incremental direct cost in the high case would be $C 6.10 per gigajoule if the technical potential were 205 exajoules compared to $C 4.15 per gigajoule if the technical potential were 225 exajoules.

1. Allowing for the value of by-products, but excluding user costs.

A lower potential for the Western Canada Sedimentary Basin than the 225 exajoules we use as a basis for our projections would result in higher future supply costs than those we project. We estimate that a reduction of the assumed ultimate technical potential to 215 exajoules would have only a minor effect on supply costs, prices, and supply/demand balances over our study period. However, the impact becomes increasingly greater the lower the assumed ultimate technical potential. With an ultimate technical potential of 205 exajoules which corresponds to the estimate for economic potential we used in 1986, supply costs would be much higher and the size of the gas market smaller than shown in our projections.

Figure 6-11

Net Incremental Direct Costs For Natural Gas at Different Assumed Ultimate Technical Potentials High Case



Chapter 7

Crude Oil and Equivalent

In this chapter we examine Canada's oil resources and the extent to which they can satisfy domestic demand for petroleum products over our study period under different economic conditions. We begin with a review of the components of the oil resource base which underlie our supply projections. We then discuss the supply of conventional crude oil from established reserves and reserves additions, synthetic crude oil and bitumen from oil sands deposits, and pentanes plus from natural gas processing. Next we examine the prospects for production from the Mackenzie Delta/Beaufort Sea and the east coast offshore areas. After reviewing the total supply of crude oil and equivalent, we discuss petroleum product demand and refinery feedstock requirements. This is followed by a discussion of oil supply/demand balances for light and heavy crude oil and the related matter of imports and exports of crude oil and products. We conclude the chapter by discussing some of the implications of our projections for Canada's major oil pipelines and the implications of alternative assumptions.

7.1 Resources

The crude oil resource base comprises all sources of crude oil, conventional as well as unconventional. Unconventional resources include bitumen from oil sands, oil shale and coal as a feedstock for liquefaction plants. Coal liquefaction is discussed in Chapter 9; we do not specifically identify coal resources for this purpose. Canada's oil shale resources are small and are unlikely to be economically viable in the time frame considered in this report. Consequently we are restricting discussion in this chapter to conventional crude oil and bitumen.

In this resource section we will discuss our estimates of technically recoverable resources of conventional crude oil and bitumen. Only part of the technically recoverable resources can be profitably exploited under specified economic conditions and that part is referred to as economically recoverable resources. The difference between technically and economically recoverable resources can be substantial. For example, exploitation of frontier resources is relatively high cost and only the more prolific fields are likely to be developed.

In our supply analysis we estimate reserves additions that are added to established reserves over the projection period and not the ultimate economic potential related to the backstop price, except for conventional crude oil in conventional areas where we have estimated both.

Technically Recoverable Resources of Conventional Crude Oil and Bitumen

Estimates of the quantities of crude oil that might ultimately prove technically recoverable can be expected to have a wide range, although the range will narrow as continued exploration and production provides more information. The estimates can change considerably over time as new technologies are developed and geological knowledge increases. A number of agencies have made resource estimates that contribute to our current understanding of recoverable resources:

- For estimates of conventional crude oil resources we complemented estimates published by the Geological Survey of Canada (GSC) and the Canada Oil and Gas Lands Administration (COGLA) with our own estimates for conventional heavy oil resources and for the enhanced recovery potential of established reserves.
- For estimates of bitumen resources, we relied on information published by the Energy Resources Conservation Board (ERCB) of Alberta.

Conventional Crude Oil

Conventional crude oil resources occur in the conventional producing areas and in the frontier regions. Resources in the former are located almost entirely in western Canada with minor quantities in eastern Canada, mainly in southwestern Ontario.

Table 7-1 provides estimates of cumulative production, remaining established reserves (discovered

resources for frontier discoveries where commercial exploitation has not yet occurred) and remaining technical potential. Together, these components provide an estimate of the ultimate technically recoverable resources. These estimates were compiled from various sources; when available we used the mid-range values. The ultimate resources could of course prove to be either higher or lower. Lower estimates have more certainty of occurrence; higher estimates have a lower probability of being attained.

In western Canada nearly half the technically recoverable resource has been produced (compare columns 1 and 4) and the potential for reserves additions is about double the currently remaining established reserves (compare columns 3 and 2) . In the frontier regions the situation is much different. There has been essentially no production to date and only about ten percent of the estimated ultimate technically recoverable resource has been discovered (compare columns 2 and 4).

Table 7-2 details the discovered resources and remaining technical potential of the frontier areas.

Of the approximately 25 discoveries in the Mackenzie-Beaufort area and 15 in the east coast offshore region, two major discoveries stand out: the Amauligak field in the Beaufort Sea and the Hibernia field east of Newfoundland. Each has reserves in the order of 80 to 100 million cubic metres. Other discoveries in these areas are smaller, ranging up to about 30 million cubic metres.

Table 7-1

Resource Estimates
Year End 1987

(Millions of Cubic Metres)

	Cumulative Production [1]	Remaining Established Reserves [b] [2]	Remaining Technical Potential [3]	Ultimate Technically Recoverable Resources [4]=[1]+[2]+[3]
Conventional Crude Oil				
Western Canada [a]	1958	730	1441 [c]	4129
Eastern Canada	10	1	37 [d]	48
Total	1968	731	1478	4177
Frontier Regions	-	523 [e]	4045	4568 [d]
Bitumen [f]				
Mining Projects	133	5167 [g]	4700	10000
In Situ Projects	22	62	38916	39000
Total	155	5229	43616	49000

Notes:

[a] Estimates for western Canada are at year end 1986.

[b] The estimates shown for frontier regions are for discovered resources. Discovered resources are estimates of the quantities of crude oil or natural gas potentially recoverable from known reservoirs, but of uncertain economic viability. The discovered resources of a reservoir will be included in established reserves when development plans have advanced to a stage where these resources can be counted on as a secure source of supply.

[c] Source: GSC, Paper 87-26, 1987 for light crude oil only; NEB for heavy crude and enhanced recovery.

[d] Source: GSC,Paper 83-31, 1984.

[e] COGLA Annual report, 1987.

[f] Source: ERCB, Report 87-18, 1988.

[g] Only 511 million cubic metres are associated with the two existing mining plants.

Table 7-2

Frontier Areas
Year End 1987
(Millions of Cubic Metres)

	Discovered Resources	Remaining Technical Potential
Mackenzie Delta and Beaufort Sea	253	1211
Grand Banks and Labrador	181	1552
Nova Scotia Offshore	23	295
Arctic Islands	66	807
Other Areas	0	180
Total	**523**	**4045**

Source: GSC, Paper 83-31, 1984 and COGLA Annual Report 1987.

Bitumen

Bitumen is an increasingly important component of Canada's crude oil supply. It occurs for the most part in three large deposits in the northern part of Alberta (Athabasca, Peace River and Cold Lake), each of which presents unique challenges with regard to extraction. Bitumen is a highly viscous hydrocarbon which does not naturally flow into a wellbore.

The volume of original bitumen in place is estimated by the ERCB at 400 000 million cubic metres. Some 24 000 million cubic metres is in areas where the deposits are sufficiently shallow for surface mining to be carried out. In these areas 10 000 million cubic metres, or 42 percent, could eventually be recovered, according to the ERCB. Of the 376 000 million cubic metres contained in deposits not amenable to surface mining, ERCB considers that only 39 000 million cubic metres or 10 percent can ultimately be recovered.

Of the three deposits mentioned, the Athabasca deposit, 400 km north of Edmonton, is the largest. It contains the most viscous bitumen but it was the first deposit to be exploited because a part of it containing about 17 percent of its bitumen can be surface mined. Two large mining plants (the Suncor and Syncrude facilities) are currently in operation and cumulative production from these plants was 133 million cubic metres as of 31 December, 1987. The bituminous sand is recovered from open pits, the bitumen and sand separated by a hot water process, and the bitumen then upgraded by refinery processes to a synthetic light crude oil. Table 7-1 shows cumulative production and remaining established reserves. Of the 5167 million cubic metres of remaining reserves only about 500 million cubic metres associated with the two existing mining plants are under active development.

In order to recover bitumen from areas where the overburden is too thick to allow surface mining, but at the same time thick enough to withstand the pressure of injected fluids, steam is injected to increase the temperature of the deposit and thus reduce the viscosity of the bitumen. The oil can then move to a wellbore and be pumped to the surface. This in situ recovery process has been successfully implemented at several projects. However such projects are currently exploiting only a small part of Canada's bitumen deposits, and cumulative production from these projects and the many pilot projects that test recovery techniques before commercial projects are considered, was only 22 million cubic metres as of 31 December, 1987.

The majority of commercial in situ production is from the Cold Lake deposit 200 kilometres northeast of Edmonton. Here the bitumen has a viscosity that is low enough to allow effective steam injection. Bitumen is also produced commercially from the Peace River deposit, some 200 km northwest of Edmonton, but here because the bitumen is more viscous, steam is injected into a thin water bearing zone underlying the bitumen from where it gradually moves upward to heat the overlying bitumen.

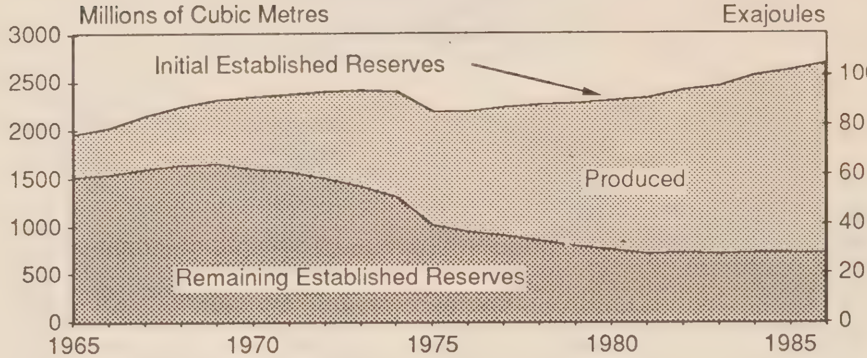
7.2 Remaining Established Reserves of Conventional Crude Oil

Established reserves are that part of the economically recoverable resources that has been discovered . Those established reserves not yet produced are termed

remaining established reserves. We estimate the remaining established reserves of conventional crude oil as of 31 December 1986 at 731 million cubic metres, of which 601 million cubic meters are light crude oil and 130 million cubic meters are heavy. Reserves by province and territory are shown in Table 7-3. The estimates, which are compiled by assessments of individual pools by Board staff, are based on current production facilities. No discovered frontier resources have been included in established reserves; they are included in additions to established reserves to the extent that they contribute to production in our supply scenarios (Section 7.6).

Figure 7-1

Established Reserves of Conventional Crude Oil Conventional Areas



Source: Appendix Table A7-1

Table 7-3

Remaining Established Reserves of Conventional Crude Oil

at 31 December

(Millions of Cubic Metres)

	1985	1986
British Columbia	19.7	19.7
Alberta	558.2	559.2
Saskatchewan	113.8	113.0
Manitoba	10.5	9.8
Southern Territories	34.2	28.1
Ontario and Other Eastern Producing Areas	1.1	0.9
Total Conventional Areas	**737.4**	**730.8**

Note: The numbers in this table have been rounded.

Figure 7-1 shows that remaining reserves declined from a peak of 1659 million cubic metres in 1969 to 716 million cubic metres in 1981; since 1981, reserves additions and production have been roughly in balance. In 1985 and 1986, production was 72 million and 69 million cubic metres respectively, while corresponding reserves additions were 69 million and 63 million cubic metres resulting in a decline of remaining reserves of 10 million cubic metres over the two year period. Reserves additions in 1986 were about twice the volumes projected in our 1986 report; they included a positive revision to established reserves of 22 million cubic metres, based mainly on performance trends which previously had been obscured by periods of constrained production.

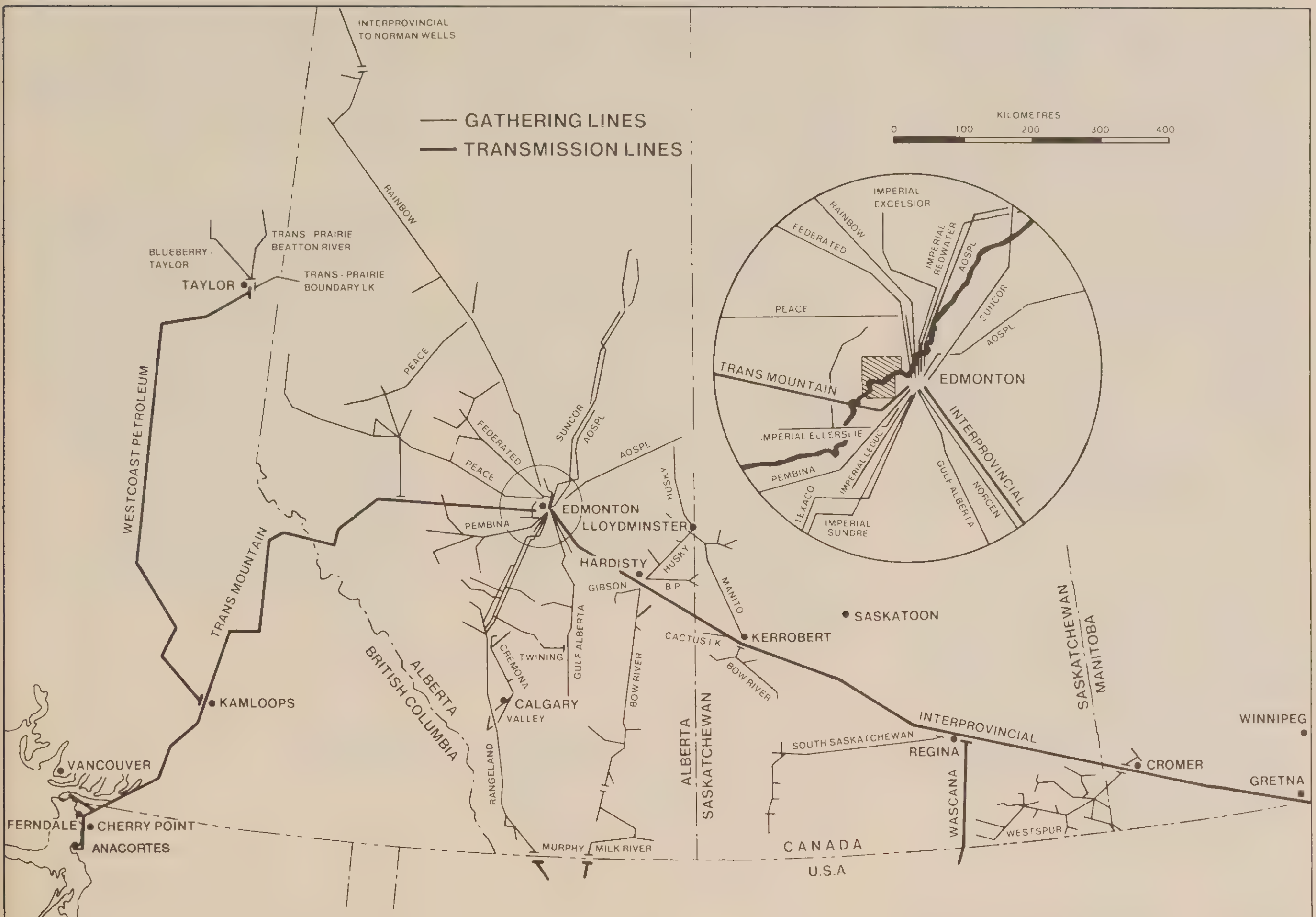
Established reserves are not particularly sensitive to crude oil prices, but the rates at which these reserves are produced will differ with different prices. The difference is related partly to the number of infill wells anticipated to be drilled under each price scenario. In our 1986 projections, the productive capacity was arbitrarily reduced in the low case to allow for fewer workovers and earlier abandonment of marginal wells than in the high case. In neither case was allowance made for production acceleration from infill wells. Such acceleration has become apparent with recent increases in the number of infill wells.

For our current estimates, in both cases we included supply attributed to production acceleration from the drilling of infill wells. We made a downward adjustment to our productive capacity projections in the low case to allow for fewer workovers and earlier well abandonments.

The total supply from currently established reserves of conventional crude oil declines from 200 thousand cubic metres per day in 1987 to only 25 thousand and 24 thousand cubic metres per day in the year 2005 for the low and high cases respectively. Appendix Table A7-2 shows the supply of light and heavy crude oil from currently established reserves by province and territory; Appendix Table A7-3 provides further detail

Figure 7-2

Major Crude Oil Gathering Lines



on the productive capacity of individual pools aggregated by gathering pipeline system and on the volume of additional supply attributed to production acceleration. Figure 7-2 shows the location of the major gathering and trunk pipelines which transport crude oil from producing fields to refining centres.

7.3 Reserves Additions - Conventional Areas

Reserves additions are economically recoverable resources that are projected to become established reserves during the projection period. Reserves additions consist of two components, appreciation of existing reserves and future discoveries. For our analysis we estimate appreciation of currently established reserves resulting from future enhanced oil recovery projects separately from all other reserves additions. The latter, which relate primarily to drilling activity, we place in a second category. These categories are discussed individually.

7.3.1 Additions from Enhanced Oil Recovery in Currently Established Pools

We define enhanced oil recovery as all recovery techniques other than those which use only the natural energy of the reservoir (termed primary recovery). Though there is some potential in established pools for reserves additions by further waterflooding (termed secondary recovery), the greatest potential for enhanced recovery is through the application of more costly methods, commonly

referred to as tertiary recovery techniques.

Less than 20 percent of light oil in place is recovered by primary techniques. Recovery can be improved to more than 30 percent by secondary and tertiary techniques. For heavy oil, tertiary recovery may increase recovery from less than 10 percent to more than 20 percent.

The most common tertiary technique for light oil involves the injection of a solvent that is miscible with the oil under reservoir conditions. In Canada this is usually some combination of methane, ethane, propane, and possibly smaller amounts of butanes and pentanes plus.

For heavy oils the most common tertiary process involves steam injection. An alternative thermal technique, that is most suitable for thin producing zones, is in situ combustion of part of the oil in the reservoir, achieved through air or oxygen injection.

Other more costly and more specialized processes such as surfactant, alkaline or polymer-assisted waterfloods are available for use for both heavy and light oil. However, these are expected to provide only minor amounts of incremental oil over the projection period.

In this report we estimate remaining technical potentials and reserves additions for enhanced oil recovery. The remaining technical potential is the estimated total incremental oil recovery from future enhanced recovery schemes in currently established pools using what is considered to be the most technically appropriate process for each pool. The reserves additions are that portion of the remaining technical potential that could be economically recovered over the projection period as judged by a comparison of supply costs and our projected oil prices. These reserves additions are distributed annually based upon our estimates of the timing of the economic projects.

Estimates of supply costs for enhanced recovery vary from project to project with $C 100 per cubic metre ($US 11 per barrel) being the minimum for both heavy and light oils. Supply costs of crude oil from hydrocarbon miscible projects will, of course, vary with the costs of injected hydrocarbon materials and, for steam injection projects, with the cost of the fuel (natural gas or perhaps in the future, coal) used to generate the steam.

Our estimates of remaining technical potentials and reserves additions for enhanced oil recovery from currently established reserves are given in Table 7-4. Corresponding estimates from the October 1986 Report are also given.

The current estimate of the remaining technical potential for miscible projects is lower than that in the October 1986 Report largely because we have reduced the prospective project areas for some of the larger miscible projects. Remaining technical potentials for the other processes are essentially the same as in the October 1986 Report. Reserves additions have been revised to reflect the current oil price projections and, in the case of the miscible process, the

Table 7-4

Enhanced Oil Recovery

(Millions of Cubic Metres)

	Waterflood	Miscible	Thermal	Chemical	Total
Remaining Technical Potential					
1986 Projection	179	271	265	30	**745**
1988 Projection	170	200	265	30	**665**
Reserves Additions (1987 - 2005)					
		Low Case			
1986 Projection	78	71	49	0	**198**
1988 Projection	87	66	22	0	**175**
		High Case			
1986 Projection	78	94	81	9	**262**
1988 Projection	96	85	42	8	**230**

Notes: Numbers may not add due to rounding.
[a] Technical and economic potentials are for enhanced recovery in pools discovered prior to 31 December 1986.

Source: Appendix Table A7-9

revised remaining technical potential.

Reserves additions of light oil from miscible flood projects in established pools are projected to total 66 million cubic metres in the low case and 85 million cubic metres in the high case. Miscible flood projects already approved by the Alberta ERCB for implementation are listed in Appendix Table A7-4. This list is used as a guide in constructing the schedule of annual reserves additions for enhanced recovery of light crude oil in the high case, shown in Appendix Table A7-7 ("Miscible" rows). In the low case the projected schedule of reserves additions is reduced relative to the high case to reflect the reduced profitability of individual projects at lower oil prices. Total reserves additions of light oil from miscible, waterflood and chemical projects in established pools amount to 123 million and 153 million cubic metres in the low and high cases respectively (Appendix Table A7-9).

Progress in the development of economically viable thermal processes is not proceeding as rapidly as we previously anticipated. Consequently our projections of reserves additions of heavy oil for this process are lower than in the October 1986 Report. They total 22 million cubic metres in the low case and 42 million cubic metres in the high case. The projected annual reserves additions from thermal recovery of heavy oil are shown in Appendix Table A7-8 ("Thermal" rows). Total reserves additions of heavy oil from thermal and waterflood projects in established pools amount to 52 million and 77 million cubic metres in the low and high cases respectively (Appendix Table A7-9).

7.3.2 Additions Related to Drilling Activity

Crude oil reserves additions which relate to drilling activity include those from new discoveries, from any future appreciation associated with these discoveries (including that from enhanced oil recovery) and from incremental volumes resulting from appreciation of currently established reserves (except for enhanced oil recovery discussed in Section 7.3.1).

We assess the motivation for producers to bring on new crude oil supplies through drilling activity by comparing projected incremental direct costs with wellhead crude oil prices in western Canada. The incremental direct cost is the estimated unit cost for exploratory and development drilling, geological and geophysical assessment, field equipment and production of crude oil associated with reserves additions in any given year. The cost of capital employed is also included by allowing for a return on invested capital. As discussed in Section 3.1 we have assumed returns on capital of 10 percent and 15 percent for the low and high cases respectively.

The basic costs used for our estimation of future incremental direct costs are as shown in Table 7-5. The basis for these costs is the same as that for natural gas explained in Section 6.3.

For natural gas, we also assess the incremental indirect costs (user costs) as described in Chapter 3. This is required for the determination of natural gas prices. For crude oil, we ignore user costs because the price of crude oil in Canada, being determined in world markets, is independent of the time path of Canadian production.

Reserves additions of crude oil per metre of exploratory drilling have been declining (Figure 7-3) and are expected to continue to decrease as prospects for new discoveries diminish. As a result, incremental direct costs increase over time. Figure 7-3 illustrates the decline in reserves additions per unit of exploratory drilling which we use as

Table 7-5

Unit Costs for Crude Oil

	Low Case	High Case
Exploratory Drilling ($C /m)	350.00	450.00
Development Drilling ($C /m)	200.00	260.00
Field Equipment ($C 1000/well)	200.00	250.00
Fixed Costs per year ($C 1000/well)	25.70	28.50
Variable Cost ($C /cubic metre of fluid produced)	1.80	2.00

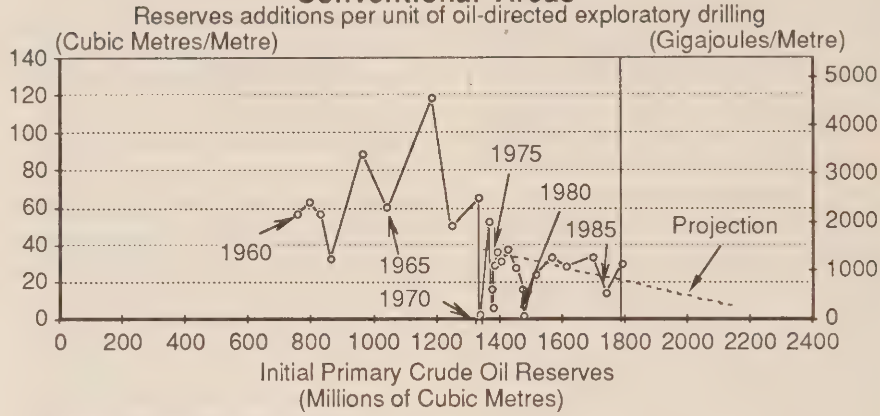
Note: Geological and geophysical costs are assumed to be 20 percent of exploration and development drilling costs in both cases.

a basis for our estimate of incremental direct costs. We assume a linear decline in the rate from current levels to zero at 2300 million cubic metres, the average expectation for ultimate technical potential for conventional light and heavy crude oil recoverable by primary mechanisms. This corresponds to an ultimate technical potential of 4177 million cubic metres for conventional areas when secondary and tertiary recoveries are included (Table 7-6). The estimated direct costs associated with increments of reserves additions resulting from these estimates are given in Appendix Table A7-6 for the two cases.

In our previous reports we estimated an ultimate potential for conventional areas by summing the initial established reserves at that time, the remaining technical potential for enhanced recovery in established pools and the remaining economic potential for reserves additions from drilling activity. (We assumed that the remaining economic potential for enhanced recovery in established pools was equal to the remaining technical potential of this category.) For this present report we have estimated the remaining technical potential for reserves additions from drilling activity based on GSC estimates for light oil and our own estimates for heavy oil. These estimates amount to 563 million cubic metres for light oil and 250 million cubic metres for heavy oil. Corresponding estimates of remaining economically recoverable resources based upon assumed backstop prices for crude oil of $C 200 per cubic metre in the low case and $C 250 per cubic metre in the high case amount to 350 million and 165 million cubic metres for light and heavy oils respectively. At these backstop prices large volumes of synthetic oil from the oil sands or from coal

Figure 7-3

Trend In Rate Of Primary Oil Reserves Additions Conventional Areas



Source: Appendix Table A7-5

Table 7-6

Comparison of Conventional Crude Oil Resource Potentials Conventional Areas

(Millions of Cubic Metres)

	Technical	Comparative Economic Estimates [a]		
	Current	Current	Oct-86	Sep-84
Light				
Initial Established Reserves	2264	2264	2165	2055
Remaining potentials:				
EOR in established pools	295	295	367	404
From drilling activity	563 [b]	350	308	280
Total Light (ultimate)	**3122**	**2909**	**2840**	**2739**
Heavy				
Initial Established Reserves	434	434	404	366
Remaining potentials:				
EOR in established pools	370	370	378	381
From drilling activity	250	165	125	140
Total Heavy (ultimate)	**1054**	**969**	**907**	**887**
Total Light and Heavy (ultimate)	**4177**	**3878**	**3746**	**3626**

Notes: Numbers may not add due to rounding.
[a] Remaining economic potentials are assumed to equal remaining technical potentials for EOR in established pools.
[b] Based on the 1988 Geological Survey of Canada's median estimate adjusted to year-end 1986.

Source: Appendix Table A7-9

liquefaction are assumed to become available. Our current estimates of ultimate potentials for conventional areas are compared with our previous estimates in Table 7-6.

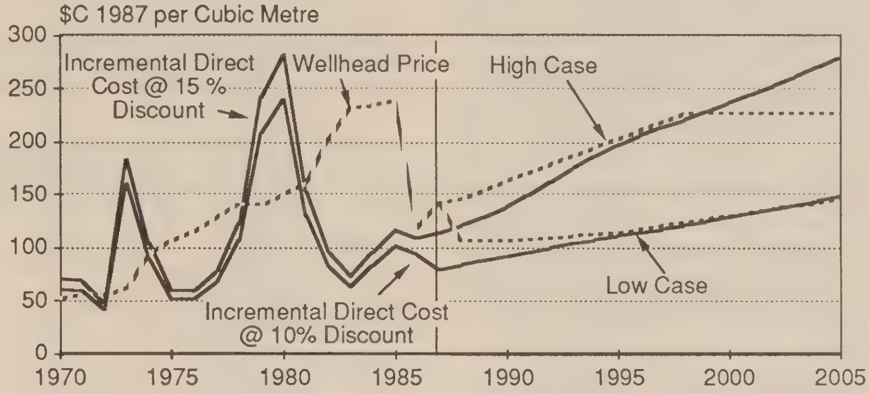
The estimated incremental supply cost curves for the low and high cases are shown in Figure 7-4. Also shown are the projected crude oil prices for West Texas Intermediate netted back to the Alberta wellhead. The historical prices are the average wellhead prices for conventional crude oil for western Canada obtained from CPA's Statistical Handbook. This figure illustrates the motivation to explore for conventional crude oil in western Canada; we assume that annual oil-directed drilling levels will be higher the greater the difference between prices and costs. Unlike natural gas, the crude oil price is not affected by Canadian oil production. The cost-price differential is determined by the changing supply costs of Canadian oil and the world oil price.

In both cases, incremental direct costs are less than prices in the near term but costs grow more rapidly than prices over the projection period. Though, in the high case, average costs exceed prices in the later years, we assume that drilling will continue in these later years, aimed at prospects that are economically attractive.

The annual oil-directed exploratory drilling levels which result from the application of our assumptions are compared with those of the October 1986 Report in Figure 7-5. The estimated oil-directed activity for 1987 is higher than we anticipated in 1986, largely because of government incentive programs.

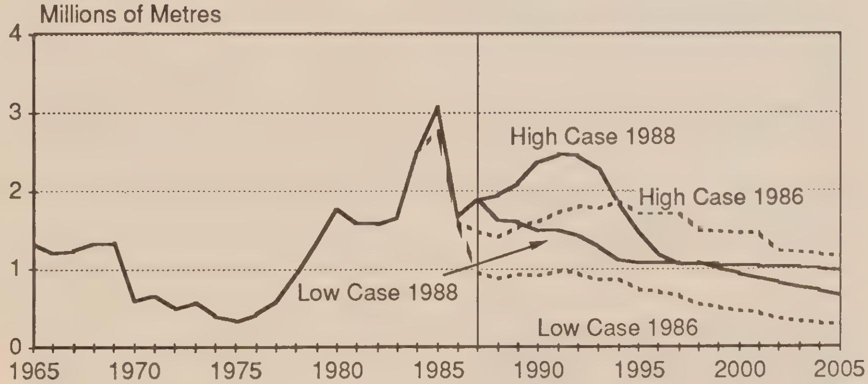
For the low case, the level of oil-directed drilling in the later years of

Figure 7-4
Wellhead Marginal Direct Costs and Prices For Crude Oil



Source: Appendix Table A7-6

Figure 7-5
Oil-Directed Exploratory Drilling Conventional Areas



Source: Appendix Table A7-5

the projection period does not decline as rapidly as we estimated in 1986 because of the larger technical potential that we are using in this analysis. For the high case, projected levels of oil-directed drilling are higher in the near term than we previously estimated; the larger technical potential that we have used in this analysis results in higher reserves additions per unit of drilling and consequently lower costs. Later in the projection period, oil-directed drilling is lower than we estimated in 1986 because of reduced economic prospects resulting from the higher levels of drilling in the earlier years.

Our projections of reserves additions resulting from drilling activity are derived using our estimates of oil-directed drilling (Figure 7-5) and our projection of the additions rates per unit of drilling (Figure 7-3). In the low case, 281 million cubic metres of conventional light crude and 98 million cubic metres of heavy crude are projected to be added over the study period. In the high case, the corresponding volumes are 315 million cubic metres and 110 million cubic metres, respectively (Appendix Table A7-9).

Estimated annual additions from drilling activity for the two cases are found in Appendix Tables A7-7 and A7-8 for light and heavy oil respectively.

7.3.3 Total Reserves Additions - Conventional Oil

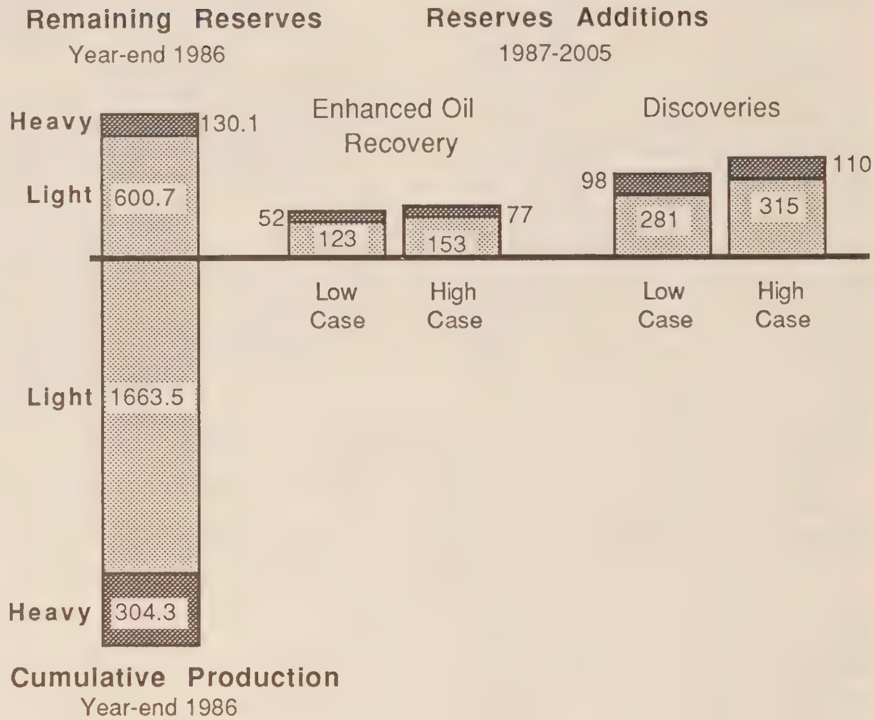
Our projected reserves additions from enhanced oil recovery in established pools and from drilling activity are compared to established reserves in Figure 7-6.

Our projection of total annual reserves additions is shown in

Figure 7-6

Reserves of Conventional Crude Oil Conventional Areas

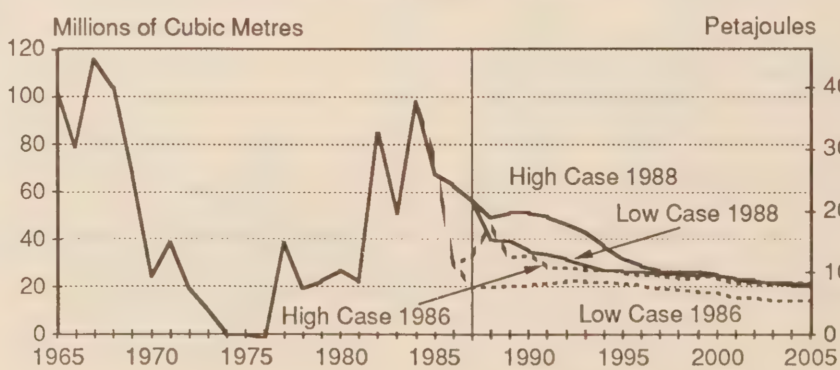
Millions of Cubic Metres



Source: Appendix Table A7-9

Figure 7-7

Total Crude Oil Reserves Additions Conventional Areas



Source: Appendix Tables A7-7 and A7-8

Figure 7-7 together with the corresponding historical data. Average annual additions for light crude oil over the projection period amount to 21 million and 25 million cubic metres for the low and high cases respectively. Actual reserves additions for light oil during the period from 1980 to 1986 averaged 47 million cubic metres. Corresponding annual averages for heavy oil are 8 million and 10 million cubic metres for the low and high cases respectively; the average over the early 1980s was 12 million cubic metres.

We are projecting total reserves additions of light and heavy conventional crude oil during the review period of 554 million cubic metres and 655 million cubic metres in the low and high cases respectively (Appendix Table A7-9). The estimates are some 197 million and 148 million cubic metres more than the corresponding estimates for the same period in the October 1986 Report. The higher current projections are due primarily to our more optimistic outlook for the ultimate technical potential.

In both cases, reserves additions of conventional crude oil are insufficient to replace production. This is reflected in the productive capacity projections (Appendix Table A7-15). In the low case, the total productive capacity from currently established reserves of conventional light and heavy crude declines from 200 thousand cubic metres per day in 1987 to 25 thousand in 2005, a reduction of 175 thousand cubic metres per day. The additional productive capacity from reserves additions over the review period amounts to only 63 thousand cubic metres per day in 2005, so that the net reduction in productive capacity over the review period is 112 thousand cubic metres per day. In the high case the net reduction is 106 thousand cubic metres per day. Our assumptions for converting reserves additions to productive capacity are shown in Appendix Tables A7-10 and A7-11.

7.4 Synthetic Crude and Bitumen

Commercial production from western Canada's bitumen deposits began in 1967 when an integrated mining and upgrading plant, owned and operated by Suncor Inc., commenced producing synthetic crude oil. After some initial problems, the plant attained an average production level of about 7 thousand cubic metres per day. A second integrated plant, operated by Syncrude Canada Ltd., became operational in 1978; total production of synthetic crude reached about 20 thousand cubic metres per day about two years later. Further improvements implemented in both plants increased production to the current levels of about 30 thousand cubic metres per day.

During the 1970s there was a gradual increase in the supply of bitumen produced from subsurface reservoirs through in situ recovery by steam injection. Accelerated development of in situ projects commenced in 1985; current production levels are some 20 thousand cubic metres a day. This production is diluted with about 8.5 thousand cubic metres per day of pentanes plus to produce a blended crude with lower viscosity that meets pipeline specifications.

The increasing levels of bitumen supply have caused concern about the adequacy of the supply of pentanes plus for diluent and about the marketability of incremental volumes of heavy crude oil. This has led to proposals for upgrading plants that would convert bitumen and/or conventional heavy crude oil to a synthetic light crude oil. The first such upgrader using conventional crude oil as feedstock is currently being constructed at the Co-op refinery in Regina and is expected to become operational in December, 1988. Construction of a second upgrader in the Lloydminster area has been announced. This plant, the "Bi-Provincial" upgrader, is expected to be operational in 1992. It is expected to use conventional crude oil, bitumen and some semi-processed heavy crude oil feedstock.

All of the bitumen currently being produced from in situ projects is sold directly to refineries, mainly in the U.S. The extent to which bitumen will continue to be sold directly to refineries or will be upgraded in the field depends on the relationship between the prices of bitumen and light crude oil. The economic value of conversion depends on whether the cost of conversion is less than the market price differential between bitumen feedstock and the upgraded product. At present the difference in the prices is about $C 60 per cubic metre whereas the cost of upgrading bitumen is about $C 85 per cubic metre. Thus to make upgrading attractive would require either a decline in the price of heavy crude relative to light or a substantial decline in the costs of upgrading.

All bitumen development, whether associated with integrated mining plants or with in situ recovery with or without upgrading, is expensive. The lowest cost alternative is in situ bitumen production (Table 7-7), but even this has a supply cost of

$US 11 per barrel and would require a minimum crude oil price of WTI in Chicago of $US 18 per barrel given the current difference in value of $US 7 per barrel between WTI and bitumen.

Our estimates of total supply costs for producing and upgrading bitumen are, however, similar to our estimated costs for producing synthetic light crude from integrated mining plants; both have costs which suggest that, in general, considerable expansion is feasible in the high case but only very limited increases in production of bitumen and synthetic light crude would occur in the low.

The bitumen deposits associated with integrated mining plants are not amenable to in situ development so that integrated and in situ projects do not compete for the same resource. The mining plants have higher front-end costs which increase project risk, but they also offer more scope for cost savings in mining and bitumen separation. There are currently three proposals each of which would add about 10 thousand to 12 thousand cubic metres per day to synthetic crude oil supply. These proposals, which have similar supply costs, are expansion of each of the two existing plants and a new plant, the "OSLO" project.

Table 7-7

Supply Costs of Synthetic Crude Oil and Bitumen

	Field or Plant Gate Supply Costs[a] ($C/m3)	Transportation Costs to Chicago ($C/m3)	Supply Costs at Chicago ($C/m3)	Supply Costs at Chicago ($US/bbl)
Bitumen from In Situ Projects[b]				
10% discount rate	65-100	20	85-120	11-15
15% discount rate	75-110	20	95-130	12-16
Synthetic Crude Oil from In Situ Bitumen Projects with Upgrading				
10% discount rate	150-185 [c]	18	168-203	21-25
15% discount rate	170-205 [c]	18	198-223	23-28
Synthetic Crude Oil from Integrated Mining Plants				
10% discount rate	170	15	185	23
15% discount rate	230	15	245	30

Notes: [a] Ranges reflect supply costs of projects currently under consideration. The ranges take into account differences in reservoir quality and differences in cost associated with opening up new areas for development.

[b] To compare the supply costs of bitumen to those of synthetic crude oil, it is necessary to add an estimate of the difference in value between bitumen and synthetic crude oil to the supply costs of bitumen. The difference is currently $C60 per cubic metre ($US 7 per barrel).

[c] We added $C85 and $C95 to bitumen supply costs to account for the cost of upgrading using 10 and 15 percent discount rates respectively.

In our low case, the supply costs shown in Table 7-7 indicate that all bitumen projects are uneconomic in the short term and only in situ development is marginally economic in the later part of the projection period. We have assumed in this case that projects now underway, or considered reasonably certain on the basis of announced plans, will proceed. This assumption results in the following additional supply during our projection period:

- Ten thousand cubic metres per day of bitumen by 1991 from the full development of in situ projects now in progress, and a further ten thousand cubic metres per day later in the projection period, when crude prices approach $US 20 per barrel.
- Eight thousand cubic metres per day of synthetic crude from the Co-op upgrader scheduled for completion in December 1988 and seven thousand cubic metres per day from the Bi-Provincial upgrader scheduled for completion in 1992.
- Six thousand cubic metres per day in total of synthetic crude oil

from the Syncrude expansion currently in progress (the CAP project), and from the announced Suncor debottlenecking project. (We assume in our projections that Suncor will make the necessary arrangements to add to its mineable reserves of bitumen in order to maintain the company's projected level of about 11 thousand cubic metres per day when the reserves at its current mine site are depleted).

In the high case, because all three options for bitumen development are indicated to be economically viable at supply costs that are comparable (allowing for the difference in value between bitumen and synthetic crude oil), it is extremely difficult to assess, solely on economic considerations, the extent to which any one is to be preferred over the others.

With respect to in situ bitumen production our approach has been to assess potential production and then to judgementally allocate production to its two uses: increased sales to export markets and increased domestic use in field upgraders. Our assessment of export prospects (discussed in Section 7.9) relates to the size of the market and to the costs of transporting bitumen. There are limits to the size of the export market at acceptable prices and the cost of diluent will probably rise over time as the supply of pentanes plus declines (Section 7.5). Both these factors suggest that, over our study period, field upgraders to process in situ bitumen will be constructed.

A recent agreement between governments and industry, aimed at construction of the OSLO integrated oil sands plant, indicates this could become a reality in the near future.

In our projections, we have attempted to achieve a reasonable balance of the available options, with projects spaced so as not to place undue pressure on the availability of labour and materials, which would cause excessive cost escalations. This results in the following additional supply during our projection period:

- Bitumen supply before deduction of upgrader feedstock requirements increases by 72 thousand cubic metres per day at the end of the projection period from the current level of just over 20 thousand cubic metres per day. Total bitumen production is some seven thousand cubic metres per day higher than we projected in 1986.
- Two upgraders, (in addition to the Co-op upgrader at Regina now approaching completion) beginning operation in 1992 (Bi-Provincial) and 1998 respectively, which add seven thousand and ten thousand cubic metres a day respectively to synthetic crude oil supply. This is similar to our 1986 projection which also included two upgrading facilities in addition to the Co-op upgrader.
- The Syncrude CAP and Suncor debottlenecking projects, as in the low case, add a total of six thousand cubic metres per day to synthetic crude oil supply by 1993. In addition, three integrated mining projects (new plants or expansions of existing plants), each producing about 12 thousand cubic metres per day are brought on production in 1996, 2000, and 2004. We recognize that this is a very optimistic projection; it reflects our price projection of $US 30 oil by 1998, somewhat lower supply costs than those estimated in 1986 reflecting technological improvement and reduced operating costs. In 1986 we included no new integrated mining plants in our projection.

The following additions to bitumen reserves are implied by the development assumptions for in situ projects:

- in the low case, 300 million cubic metres;
- in the high case, 750 million cubic metres.

In addition some of the bitumen reserves amenable to surface mining will be developed:

- in the low case 140 million cubic metres when Suncor opens a new mine in the late 1990s to continue operation of its plant when the current mining lease approaches depletion;
- in the high case 600 million cubic metres resulting from continuation of the Suncor operation when the current mine is depleted and from three new mining plants.

7.5 Pentanes Plus

Pentanes plus is included as a component of crude oil and equivalent because like crude oil it is used as refinery feedstock. Pentanes plus is a natural gas liquid and as such is discussed further in Chapter 8.[1]

---

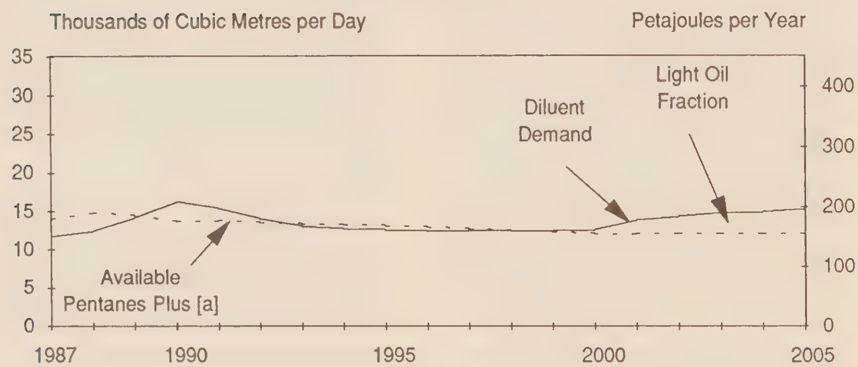
1. In the projections of supply of crude oil and equivalent shown in Table A7-15 we have excluded the small amounts of pentanes plus which are contained in NGL mixes used in enhanced oil recovery schemes.

While the end use for pentanes plus is as refinery feedstock, it satisfies two important demands along the way. When blended with conventional heavy crude oil or bitumen it acts as a viscosity reducing agent to facilitate pipeline transportation. Some pentanes plus must also be left in NGL mixes transported on the IPL pipeline in order to meet the vapour pressure requirements of storage facilities at Superior, Wisconsin.

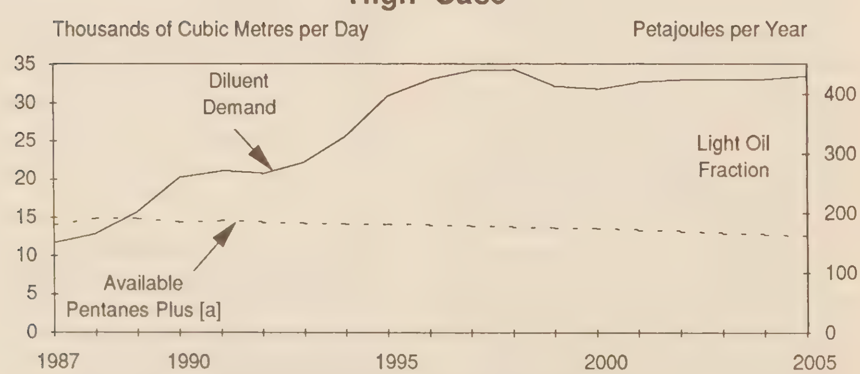
In order to reduce the viscosity of bitumen to an acceptable level for movement in existing pipeline systems it is necessary to add approximately 0.43 cubic metres of pentanes plus to each cubic metre of bitumen. For conventional heavy crude oil from the Lloydminster area, about 0.27 cubic metres of pentanes plus per cubic metre is required.

The supply of pentanes plus is unlikely to be adequate to meet the demand for diluent given our projections of heavy oil production. As can be seen in Figure 7-8 we have assumed that diluent demand in excess of available pentanes plus will be met by a light oil fraction. We have reduced our light oil supply accordingly.

Figure 7-8
Diluent Supply and Demand
Low Case



High Case



[a] To obtain pentanes plus available for use as diluent, supply in Appendix A7-15 must be reduced by approximately four thousand cubic metres per day.

Other alternatives include recycling of diluent from eastern refineries to Alberta, importing pentanes plus, using oil in water emulsions, using viscosity improvers, upgrading heavy oil and bitumen in regional upgraders to the quality currently required for transportation, and constructing pipeline facilities to handle heavier crudes. The use of any alternative to pentanes plus is likely to increase the cost of bitumen at the refinery gate.

Recycling of diluent between bitumen deposits at Cold Lake and Edmonton refineries is already taking place and occasionally small volumes of refinery naphtha have been used as diluent. The Co-op upgrader at Regina included in our projections does not reduce diluent requirements because the diluent is consumed as feedstock. However, our projections of other upgrading facilities do reflect reduced diluent requirements as feedstock is assumed to be transported to these facilities either in an unblended form or using recycled diluent.

For various reasons, some pentanes plus will be unavailable for diluent purposes. This includes feedstock requirements for the Bowden refinery in Alberta (800 cubic metres per day in 1987), volumes moved to Sarnia in NGL mixes (980 cubic metres per day in 1987), volumes blended in light crude oil in the field (about 1500 cubic metres per day in 1987), volumes associated with Mackenzie Delta gas production, and in the high case, volumes associated with east coast gas production beginning in 2004. In 1987, approximately 850 cubic metres per day of production from Shell's Waterton gas plant in Alberta which were previously shipped to Montana, were made available for diluent through pipeline modifications.

7.6 Frontier Areas

As discussed in Section 7.1, Canada's frontier areas have substantial discovered resources of crude oil. Ultimate technically recoverable resources of these areas could be at least as large as those of the Western Canada Sedimentary Basin. Development of these resources has so far not been economically attractive, but companies are continuing to examine ways to develop the pools that have been found. Further exploration would undoubtedly be encouraged were profitable development of discovered pools to occur.

Table 7-8 summarizes our estimates of the supply costs of the more promising frontier discoveries. Supply costs for Hibernia are shown with and without the effect of the federal grant set out in the "Statement of Principles" signed in July, 1988 by the Federal and Newfoundland governments and the members of the Hibernia consortium.

The development plan for the Hibernia field, which includes the construction of a fixed concrete base production platform, has already been conditionally approved by the Canada-Newfoundland Offshore Petroleum Board. Under this plan, maximum production from the field would be about 17.5 thousand cubic metres per day which could be maintained for about 9 years before production would start to decline. Based on this production rate and the capital and operating costs outlined in the "Statement of Principles" we estimate Hibernia supply costs at $US 24 to 27 per barrel.[1] This would render development attractive only in our high

1. The project costs in the "Statement of Principles" are higher than those we used to derive the supply cost estimates in our 1986 report. At that time we estimated a supply cost of $US18-22 at Chicago at a 10 percent discount rate.

Table 7-8

Supply Costs of Frontier Crude Oil

	Supply Costs at Fieldgate ($C/m3)	Transportation Costs to refinery centre ($C/m3)	Supply Costs at Chicago or Equivalent Centre ($C/m3)	($US/bbl)
East Coast Offshore				
Hibernia [a]				
10% discount rate	-	-	190	24
15% discount rate	-	-	220	27
Hibernia [a] (with federal grant)				
10% discount rate	-	-	170	21
15% discount rate	-	-	195	24
Fields that can be Developed with Floating Production Platforms				
10% discount rate	95-150	10	100-160	13-20
15% discount rate	105-160	10	115-170	14-21
Mackenzie Delta/Beaufort Sea				
Amauligak				
10% discount rate	75	70	150	19
15% discount rate	85	90	170	21

Notes: [a] Based on capital requirements and operating costs shown in "Statement of Principles" of 18 July, 1988 which are inclusive of transportation.

case. However, the discount rates we used to calculate these supply costs do not reflect any particular fiscal or financial regime or measures of project support.

We estimate that the federal grant of $C 1.04 billion provided for in the "Statement of Principles" would reduce the supply costs by about $US 3 to $US 21-24 per barrel, still higher than the oil prices projected in our low case. We have not done a detailed analysis to take into account corporate tax positions; such an analysis could show commercial viability at low case prices.

Table 7-8 indicates that on the basis of our supply analyses, small pools in the Grand Banks and Scotian Shelf areas could be produced from floating production platforms at supply costs that would be viable in the low case, as well as in the high.

The Mackenzie Delta-Beaufort Sea area is distant from major refinery areas and sizeable reserves are required to justify major investments in a transportation system. The discovery of the Amauligak field, which demonstrated a high productive capacity and has larger reserves than other fields previously found in the area, has substantially improved the prospects for development.

Our supply cost estimates for the Amauligak field (Table 7-8), indicate that development would be, marginally economic at best, in the low case, but viable in the high. As production begins to decline after six or seven years, other fields could be brought on to maintain pipeline throughput. Should substantial new offshore reserves be discovered before pipeline construction starts, simultaneous connection of these and Amauligak could be economically attractive.

Based on these supply cost considerations we have developed the following supply projections for the low case:

- We assumed that for the east coast offshore region only lower cost developments using floating production platforms would proceed, and that the Hibernia fixed platform project would not. As these projects have a relatively short lead time, we project production to commence in 1996, increasing gradually to 13 000 cubic metres per day in 2001. We emphasize however, that our assessment was conducted without full knowledge of the impact on supply costs of the corporate tax positions of the Hibernia partners.

- For the Mackenzie-Beaufort area we assumed that Amauligak development would not proceed, although our supply cost analysis suggests that pipeline construction could take place in the last few years of the projection period. This would, however, not materially affect our supply projections as little or no oil would be produced before 2005[1].

In the high case, we project high levels of production from both the east coast offshore and the Mackenzie-Beaufort areas:

- Production from the east coast offshore fields starts in 1992 at 1500 cubic metres per day, reaches a peak of 28 000 cubic metres per day in 1996 and then declines to a plateau of 25 000 cubic metres per day for the remainder of the projection period. The initial production is from small pools using floating production platforms with Hibernia coming on stream in 1995.

- Production from the Mackenzie-Beaufort area is projected to start in 1990 with tanker shipments from Amauligak to the west coast or the Pacific Rim at an average annual volume of about 2 000 cubic metres per day. Such shipments would make it possible to evaluate reservoir characteristics and would provide early cashflow. A pipeline to Alberta is projected to be completed in 1997, which allows production from this area to increase significantly, reaching a level of 24 000 cubic metres per day in 1999.

Total frontier production reaches only 13 000 cubic metres per day by the year 2005 in the low case, compared with 48 000 cubic metres in the high.

In the low case these developments imply that some 100 million cubic metres of frontier oil, nearly 20 percent of the currently discovered resource, will be included in established reserves during the projection period. In the high case at least 310 million cubic metres of frontier oil will be included in established reserves during the projection period, about 60 percent of currently discovered resources.

---

1. In order to provide a means of transporting condensate produced in conjunction with natural gas to market, we assumed that a small diameter pipeline for this purpose would be constructed from the Mackenzie Delta to Norman Wells with completion of a gas pipeline to the Mackenzie Delta. Depending on available pipeline space small volumes of crude oil could be transported with the condensate.

Minor tanker shipments from the Bent Horn field in the Arctic Islands have occurred since 1985. These shipments, which have been intended to show the commercial viability of shipping crude oil out of the high Arctic by icebreaking tanker, are likely to continue in both scenarios.

7.7 Total Supply

Crude oil supply has increased every year since 1982. This trend continued in 1986 and 1987 notwithstanding the major drop in world crude oil prices that occurred during the first quarter of 1986. How long this trend will continue after 1988 depends very much on future crude oil prices, but the overall supply outlook has improved substantially since our 1986 report.

Table 7-9 is a summary of our current projections and those made in 1986 for light and heavy crude oil supply. The current projections are shown by component in Figure 7-9 together with historical production levels. Additional detail on the contribution of the individual components of oil supply can be found in Appendix Table A7-15.

Our current projections are considerably higher than those in our 1986 report. This can be attributed partly to the use of a higher estimate of technically recoverable resources, and higher prices in 1987 than we projected in 1986. However, a more important factor was the change in operating climate resulting from various government and industry actions such as:

- the introduction of drilling, exploration and development incentives after the decline in oil prices in 1986,
- reduced regulation of production and exports,
- implementation by industry of cost cutting measures which lowered operating costs in most areas, especially in bitumen and synthetic crude oil production.

These factors had an immediate and substantial positive effect on supply. As a result, we increased our projections of 1988 supply by 33 thousand and 29 thousand cubic metres per day in the low and high cases respectively over our projections in 1986. The differences grow to 50 thousand and 51 thousand cubic metres per day by 1990. The short term differences are mainly in conventional crude oil and bitumen supply in western Canada. In the longer term there are also major increases over the 1986 projections in pentanes plus and frontier oil supply in both cases and in synthetic crude from integrated mining plants in the high case.

Table 7-9

Productive Capacity of Crude Oil

(Thousands of Cubic Metres per Day)

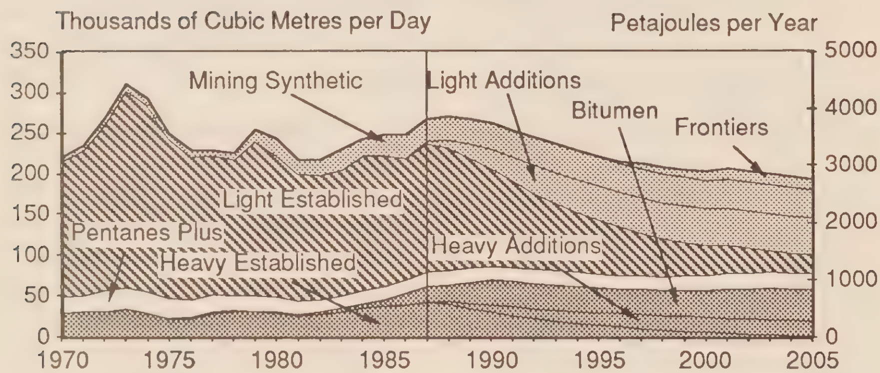
		1987	1988	1989	1990	1995	2000	2005
Low Case								
Current Report								
	Light	195	196	194	184	161	148	134
	Heavy	74	76	75	79	59	55	61
	Total	**269**	**272**	**268**	**263**	**221**	**203**	**195**
1986 Report								
	Light	194	184	176	163	123	100	81
	Heavy	63	55	48	50	47	43	41
	Total	**257**	**239**	**224**	**213**	**170**	**143**	**122**
High Case								
Current Report								
	Light	195	199	199	192	176	202	198
	Heavy	74	80	83	98	128	122	124
	Total	**269**	**279**	**282**	**289**	**304**	**324**	**322**
1986 Report								
	Light	195	186	178	165	133	150	128
	Heavy	68	64	63	73	94	94	114
	Total	**263**	**250**	**241**	**238**	**226**	**244**	**242**

Note: The numbers in this table have been rounded.

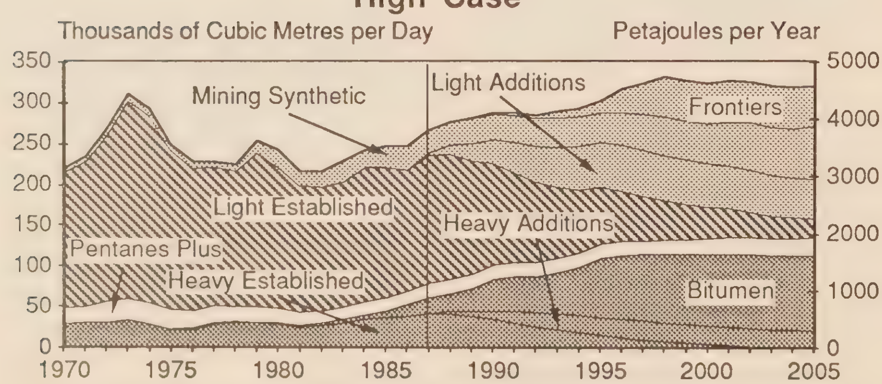
Source: Appendix Table A7-15 and October 1986 Report.

Figure 7-9 shows that total supply of crude oil and equivalent gradually declines in the low case from a peak of 272 thousand cubic metres per day in 1988 to 195 thousand cubic metres per day in 2005. In this case light crude oil supply is declining substantially as we assume no additional upgraders after completion of the Bi-Provincial plant, no further integrated mining plants and only minor frontier developments with floating production platforms off the east coast. Heavy crude oil supply (which we define as net of upgrader feedstock) is also declining because of increasing demand for upgrader feedstock. Conventional heavy crude oil supply declines from a peak of 45 thousand cubic metres per day in 1988 to 21 thousand cubic metres per day in 2005. Supply of bitumen is projected to increase from 20 thousand to 30 thousand cubic metres per day from now to 1990 on the basis of projects now under development. After 1990, bitumen supply is essentially stable until 1998 when the projected level of crude oil prices makes development of bitumen again economic. In the latter part of the projection period, bitumen production increases to 40 thousand cubic metres per day.

Figure 7-9
Supply of Domestic Crude Oil and Equivalent
Low Case



High Case



Source: Appendix Table A7-15.

In the high case, total supply grows from 279 thousand cubic metres per day in 1988 to a level of about 320 thousand to 330 thousand cubic metres per day between 1997 and 2005. Light crude oil supply is relatively constant in this case; the growth in supply comes almost entirely from projected increases in heavy crude oil production based on bitumen development. The gradual decline in conventional production in western Canada causes an initial decrease in total light crude supply after 1989 but a reversal of this trend is projected in 1994 as a result of:

- three additional integrated mining plants and small expansions of existing mining plants,
- the construction of two new upgrading plants in addition to the Co-op upgrader, and finally,
- major frontier developments in the east coast offshore and Mackenzie Delta-Beaufort Sea areas.

A summary of the timing of all major energy projects is provided in Appendix Table A7-18.

7.8 Petroleum Product Balances and Refinery Feedstock Requirements

In Chapter 4 we assessed the prospects for oil use in Canada in terms of the total demand for refined petroleum products. In order to determine the implications of petroleum product demand for the supply and demand balances for

crude oil, product demands must be converted to the corresponding requirements for refinery feedstocks in Canada. This is the subject of this section.

In assessing the implications of product demand for crude oil needs in Canada, we take into account the existing refinery distillation capacity by region, the flexibility of the refineries to manufacture different types of products, and the role played by product exports and imports.

Refinery Capacity

In 1985, there were 29 refineries in Canada with a combined total distillation capacity of 304 thousand cubic metres per day. There was essentially no change in total refinery capacity between 1985 and 1988 (Table 7-10).

In 1987, Petro-Canada's refinery in Newfoundland, which had been closed down for several years, was sold to the Bermuda-based Newfoundland Energy Company. It commenced operations later in the year adding 16 thousand cubic metres per day of refining capacity to the Atlantic region. Esso Petroleum increased the capability of its Dartmouth refinery to use a range of crude oils. Gulf Canada closed down its refinery in Montreal (capacity 12 thousand cubic metres per day) in 1986. Other refiners in eastern Canada increased their capability to produce light products. In Ontario, Suncor installed a hydrocracker and reduced distillation capacity by 3 thousand cubic metres per day, and in Montreal Petro-Canada installed a Canmet hydrocracker at its refinery. Consumer's Co-op in Regina is completing a project to upgrade heavy crude oil to light for further processing in its refinery. Parkland Industries of Red Deer, Alberta purchased Shell Canada's Bowden refinery. The Company already owns a network of service stations in Alberta and Saskatchewan and is also active in oil exploration.

Table 7-10

Refinery Capacity
(Thousands of Cubic Metres per Day)
(Crude Oil and Equivalent)

	As of January 1985	1988
Atlantic Provinces	36	52
Quebec	62	50
Ontario	103	99
Prairie Provinces	75	73
British Columbia/N.W.T	28	29
Total Canada	**304**	**303**

Since 1980, the refining industry has made improvements to its processing equipment to increase the production of light products such as gasoline and distillates; this caused heavy fuel oil production to fall sharply, from 14 to 7 percent of total refinery output. Further improvements in product yield factors are expected to meet changing demand patterns and product specifications, for example; the phasedown of lead in gasoline and sulphur in diesel fuel. In addition, investments may be required to process increasing quantities of synthetic crude oil during the review period.

In recent years, refiners have been increasing inter-regional transfers of semi-processed oil for manufacturing finished products. During the projection period, we expect that these transfers, along with transfers of finished products, will increase rapidly, especially between the Edmonton refinery complex and Vancouver, British Columbia.

Refinery Feedstock Requirements

In the low and high cases, the total demand for oil products increases from about 248 thousand cubic metres per day in 1987 to 294 thousand and 297 thousand cubic metres per day respectively by the year 2005, an increase of close to 50 thousand cubic metres per day.

Some of this increase can be met by increasing refinery utilization. In eastern Canada, capacity utilization can be increased from its current level (81 percent in 1987) to about 90 percent during the projection period. These increases in the utilization of existing refinery capacity satisfy over 20 thousand cubic metres per day of the increase in product demand.

The remaining demand will have to be met by new refinery capacity or by increased imports. We estimate that the cost of importing oil products will be less than the cost of constructing new refinery capacity; indeed it seems probable that, on a unit of production basis, the cost of capital alone for a new refinery in Canada would exceed the marginal cost of refining for offshore refineries having surplus capacity. Major international oil companies with spare refining capacity are likely to optimize their world-wide refining operations to reduce costs. In such circumstances we think it doubtful that new refineries will be built in Canada during the study period. As a consequence, we foresee imports of petroleum products increasing to 50 thousand cubic metres per day in both the low and high cases.

More generally, exports and imports of oil products will continue

to play an important role in the supply-demand balance. We have assumed that refiners and independent marketers will continue to export and import products during the review period, in order to overcome seasonal and regional imbalances in demand and to operate refineries most efficiently. Further, companies with established export markets in the United States will probably continue supplying these customers. For example, the Come-by-Chance refinery in Newfoundland, which was recommissioned as an export refinery, is expected to export the bulk of its production regardless of the Canadian supply and demand situation.

Total exports of petroleum products in 1987 were about 27 thousand cubic metres per day. We estimate that exports will increase to about 33 thousand cubic metres per day in 1988 and remain at that level during the review period. About 50 percent of these exports will be from the Atlantic region.

In 1987, total imports of petroleum products averaged 22 thousand cubic metres per day. Some large industrial consumers and utilities will continue importing heavy fuel oil for their own consumption and we expect some independent marketers to penetrate western Canadian markets by importing oil products into British Columbia. Independent marketers are also expected to import oil products on a spot basis taking advantage of low international spot prices as they occur. In keeping with industry's past practices, Canadian refiners are not expected to reduce crude runs in order to import products on a spot basis.

Our outlook for crude oil demand in Canada is illustrated in Table 7-11.

Table 7-11

Refinery Feedstock Requirements

(Thousands of Cubic Metres per Day)

Low Case

	1987	1990	1995	2000	2005
Demand for Petroleum Products	221.0	229.0	243.9	249.3	260.0
Product Exports	27.0	34.6	33.9	33.8	33.8
Product Imports	(22.5)	(24.0)	(37.9)	(42.0)	(50.4)
Inventory Change, Refinery Use, Loss and Other Adjustments	10.4	15.4	16.8	17.8	17.0
Refinery Feedstock Requirements	235.9	255.2	256.7	258.9	260.6
Supplied by:					
Partially Processed Oil, Other Material and Gas Plant Butanes	(10.7)	(11.9)	(10.4)	(10.4)	(10.2)
Crude Oil	225.2	243.1	246.3	248.5	250.5
Light	201.2	218.1	217.3	220.3	221.4
Heavy	25.0	25.0	29.0	28.2	29.1

High Case

	1987	1990	1995	2000	2005
Demand for Petroleum Products	221.0	226.9	240.2	252.4	263.9
Product Exports	27.0	34.3	33.1	33.0	33.1
Product Imports	(22.5)	(20.0)	(31.4)	(40.9)	(49.5)
Inventory Change, Refinery Use, Loss and Other Adjustments	10.4	15.2	17.4	18.3	17.5
Refinery Feedstock Requirements	235.9	256.3	259.3	262.8	265.0
Supplied by:					
Partially Processed Oil, Other Material and Gas Plant Butanes	(10.7)	(11.9)	(11.0)	(11.9)	(11.9)
Crude Oil	225.2	244.4	247.3	250.8	253.1
Light	201.2	218.8	217.3	219.1	220.4
Heavy	25.0	25.6	30.0	31.7	32.7

Source: Appendix Table A7-16

In eastern Canada (i.e. Ontario and east), in both cases, crude runs increase from 153 thousand cubic metres per day in 1987 to 175 thousand cubic metres per day by 2005, largely because of the recommissioning of the Come-by-Chance refinery. In western Canada, crude runs could rise from about 83 thousand cubic metres per day in 1987 to 86 thousand cubic metres per day in the low case and 90 thousand cubic metres per day in the high case by the year 2005. This increase would occur in the Prairie Region, especially in the Edmonton refinery complex, as these generally newer, larger and more efficient refineries expand their supply orbit farther into British Columbia.

7.9 Supply/Demand Profiles

In 1987, total crude oil and equivalent hydrocarbon production in Canada exceeded domestic consumption by about 37 thousand cubic metres per day. Refineries in Canada generally use light crude oil to manufacture petroleum products; most heavy crude oil production is exported. In order to assess the extent to which domestic feedstock demand can be satisfied from indigenous production, it is essential to determine supply/demand balances for light and heavy crude oil separately.

7.9.1 Light Crude Oil

In Table 7-12, we show the supply and demand outlook for light crude oil and equivalent. Total light crude oil supply includes conventional light crude oil, synthetic crude and pentanes plus.

In 1987, production was about 188 thousand cubic metres per day compared with domestic refinery demand of 202 thousand cubic metres per day. Pipeline capacity restrictions caused about 7 thousand cubic metres per day of crude oil production to be shut in.

Canada exported about 44 thousand cubic metres per day of light crude oil in 1987 mainly to the U.S. midwest region. Canadian producers are able to supply these markets more economically than they can supply Canadian markets east of Montreal. Imports of light crude oil to eastern Canada were about 58 thousand cubic metres per day so that net imports were 14 thousand cubic metres per day.

Table 7-12

Supply and Disposition of Light Crude Oil and Equivalent

(Thousands of Cubic Metres per Day)

	1987	1990	1995	2000	2005
Low Case					
Domestic Supply [a]	188	184	161	148	134
Imports	58	69	70	80	95
Total Supply	246	253	231	228	229
Total Domestic Requirements	202	218	217	221	222
Excess Supply or Potential Exports	44	35	14	7	7
Total Disposition	246	253	231	228	229
Net Imports of Light Crude Oil	14	34	56	73	88
High Case					
Domestic Supply [a]	188	192	176	202	198
Imports	58	69	56	44	44
Total Supply	246	261	232	246	242
Total Domestic Requirements	202	219	217	219	220
Excess Supply or Potential Exports	44	42	15	27	22
Total Disposition	246	261	232	246	242
Net Imports of Light Crude Oil	14	27	41	17	22

Notes: The numbers in this table have been rounded.
[a] Domestic supply is net of diluent requirements for pipelining heavy crude oil.

Source: Appendix Table A7-17

During the projection period, we have assumed that western Canada and Mackenzie/Beaufort crude oil will be used to satisfy refinery demand in western Canada first, then in Ontario and lastly in Montreal refineries. We have also assumed that exports via the Rangeland and Milk River pipeline systems will remain constant at 7 thousand cubic metres per day. In addition, we have assumed that all offshore production from the east coast will be delivered to the Atlantic Region refineries; if this production is exported, the levels of exports and imports will increase but the net position will remain unchanged.

Use of domestic light crude oil in Canada declines in the low case from about 144 thousand cubic metres per day in 1987 to 127 thousand cubic metres per day in 2005, because of declining supplies of light crude oil in western Canada. In the high case, the use of domestic light crude oil increases to 177 thousand cubic metres per day in 2005, as a result of frontier production.

In 1987, synthetic crude oil output was approximately 29 thousand cubic metres per day representing about 15 percent of total light crude oil production. Canadian refineries, primarily in the Prairie Region and Ontario, consumed nearly 80 percent of this production with the remainder being exported to the United States. Synthetic production increases in both cases to about 50 thousand cubic metres per day and 90 thousand cubic metres per day by 2005 in the low and high cases respectively. We assume that this production would find markets in Canada because of declining supply of conventional light crude oil.

Light crude oil imports in 1987 represented about 29 percent of our total light crude oil requirements. In the low case, imports increase to over 40 percent of total light crude runs by 2005. In the high case, during the early part of the study period, the import proportion increases; it then declines as frontier production comes on stream in the 1990s. As noted, a significant portion of imports is used to manufacture products for the export market; we expect this to continue.

7.9.2 Heavy Crude Oil

The heavy crude oil supply and demand outlook is shown in Table 7-13. Heavy crude oil productive capacity in the low case declines slightly but in the high case pro-

Table 7-13

Supply and Disposition of Heavy Crude Oil

(Thousands of Cubic Metres per Day)

Low Case

	1987	1990	1995	2000	2005
Domestic Supply [a]	74	79	59	55	61
Imports	7	7	7	7	7
Total Supply	81	86	66	62	68
Total Domestic Requirements	25	25	29	28	29
Excess Supply or Potential Exports to Northern Tier	56	61	37	34	39
Total Disposition	81	86	66	62	68
Net Exports	49	54	30	27	32

High Case

	1987	1990	1995	2000	2005
Domestic Supply [a]	74	98	128	122	124
Imports	7	7	7	7	7
Total Supply	81	105	135	129	131
Total Domestic Requirements	25	26	30	32	33
Excess Supply or Potential Exports to:					
-Northern Tier	53	67	81	83	84
-Other	3	12	24	15	14
Total	56	79	105	98	98
Total Disposition	81	105	135	129	131
Net Exports	49	72	98	90	91

Notes: The numbers in this table have been rounded.
[a] Domestic supply includes diluent.

Source: Appendix Table A7-17

duction rises sharply to about 125 thousand cubic metres per day by 2005 as a result of a rapid increase in bitumen production. In both cases, productive capacity exceeds domestic usage throughout the review period.

Canadian refineries currently process only a limited volume of domestic heavy crude oil. Generally, the domestic demand for indigenous heavy crude oil is seasonal and depends mainly on the demand for asphalt. Processing of domestic heavy crude oil for the manufacture of refined products other than asphalt is currently limited by available refinery processing facilities. Certain improvements have taken place to enhance heavy crude oil refining capability at one plant in Ontario. We anticipate very little additional improvement in refining facilities to process heavy crude oil.

The estimated domestic requirement for heavy crude oil, excluding upgrader feedstock, increases in the low and high cases from about 25 thousand cubic metres per day in 1987 to 29 thousand and 33 thousand cubic metres respectively in 2005. Of this, 7 thousand cubic metres per day is imported by refineries in Quebec and the Atlantic Provinces; this is expected to continue during the review period. Demand for total heavy crude oil as a percentage of total crude oil requirements remains at about 12 percent.

Canada exports the bulk of its heavy crude oil production, primarily to the United States. Figure 7-10 portrays the major locations to which Canadian heavy crude oil has been exported during the first half of 1988.

Crude oil requirements in the United States will be determined by demand for light oil products. Over the review period, U.S. product demand seems likely to grow at an annual average rate of about 1 percent under a price scenario similar to that of our high case. In the low case, the surplus of Canadian heavy crude oil remains at about the current level and export markets are not likely to pose a problem.

Canadian heavy crude oil is currently exported primarily to the United States Northern Tier (the midwest and Montana), where total refining capacity is about 190 thousand cubic metres per day, of which about 85 thousand cubic metres per day represents heavy crude oil processing capability. Our exports currently amount to 60 thousand cubic metres per day. This suggests that, with aggressive marketing, more Canadian heavy crude oil could be sold in the Northern Tier.

In our view, it is plausible to expect that U.S. refiners in this area will place increasing reliance on Canadian supply as long as pipeline capacity is available and crude oils are competitively priced. Furthermore, as deliveries of Wyoming Sour crude oil to this area decline with falling production, Canadian crude oil could capture additional market share. The existing Northern Tier market for heavy crude oil is also capable of growth as and if U.S. refiners install upgrading facilities to process more heavy crude oil. Decisions to make these investments are complex and the extent to which they will occur is uncertain; however, our projections do incorporate a degree of light to heavy substitution. These factors, combined with the high capacity utilization rates to meet product demand, imply that Canadian heavy crude could well play an increasing role in meeting the Northern Tier demand for feedstocks.

In the high case, we have included modest exports of Canadian heavy crude oil out of Montreal to the U.S. gulf coast and eastern seaboard. From the west coast, we have assumed that the full potential of Trans Mountain Pipe Line system's recently approved expansion is used to carry heavy crude oil to export. The Trans Mountain expansion would provide additional access to markets in the U.S. and other Pacific rim countries, particularly Japan and the rapidly growing economies of the far east such as South Korea. However, these markets, which have much greater potential than that included in our estimate, remain highly competitive because of the availability of crude oils from the middle east, far east and, more recently, Australia. In addition, potential exports under the "Other" category include modest volumes for which markets have yet to be determined.

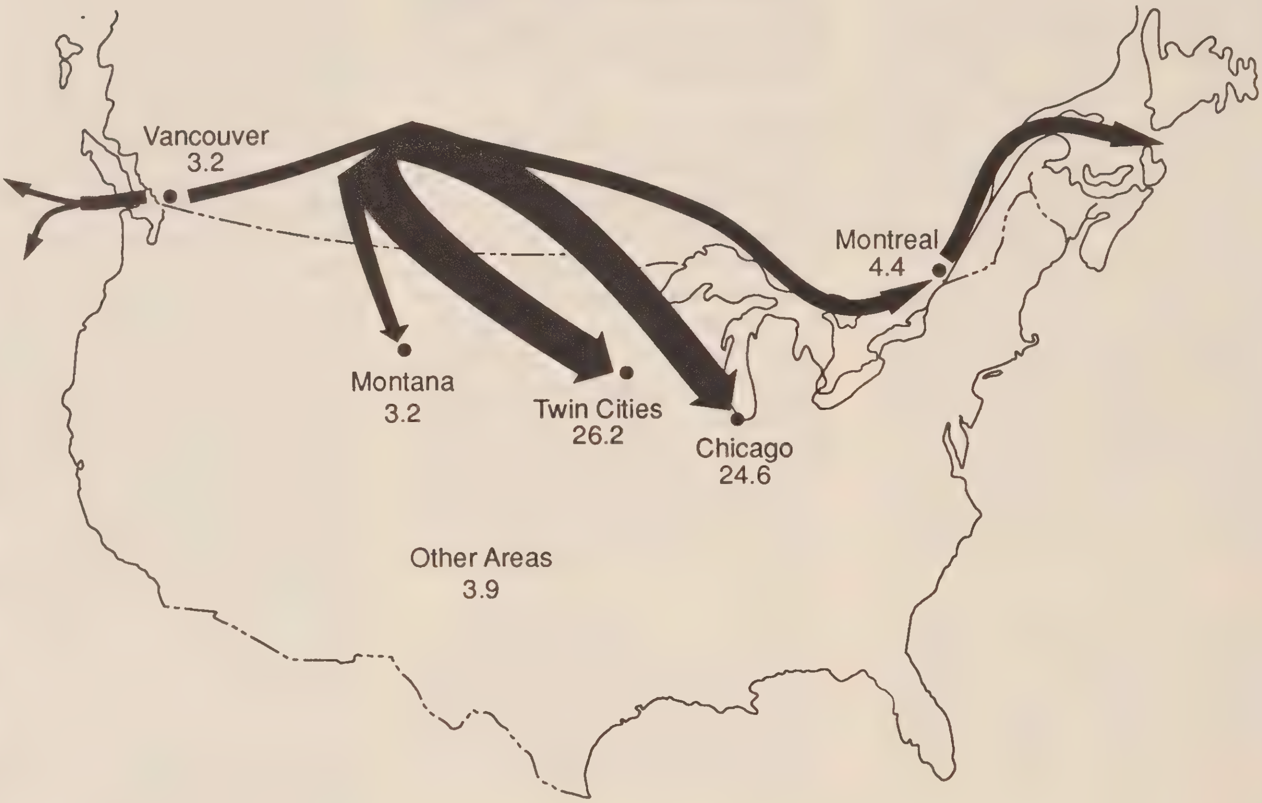
Another potential market is the Wood River, Illinois refining area, south of Chicago. We have assumed that this market has the potential to take 15 thousand cubic metres per day of heavy crude oil. For Canada to gain access to this market, however, pipeline capacity would have to be put in place either through reversal of one of the two existing pipelines currently moving oil north from Wood River to Chicago, or the construction of a new pipeline.

In summary, it is difficult to assess whether further expansion of U.S. markets will in fact be the most attractive option for heavy crude oil producers. In the high case, the Northern Tier market may not be sufficient to absorb the high levels of Canadian heavy crude oil pro-

Figure 7-10

Exports of Heavy Crude Oil by Market
1st Half 1988

(Thousands of Cubic Metres per Day)



duction we have projected. This, coupled with the advantages for Canadian producers of a diverse market, may make the expansion of offshore sales likely. In either situation, additional Canadian pipeline capacity would have to be built, given our assumptions on supply in the high case.

7.9.3 Exports and Imports of Crude Oil and Products

In 1987, Canada was a net exporter of total crude oil and equivalent hydrocarbons to the extent of 35 thousand cubic metres per day. This was attributable largely to our exports of heavy crude oil. Our projections imply that in the low case, the net export position deteriorates rapidly. By 2005 net imports are about 56 thousand cubic metres per day. In the high case, in contrast, increasing heavy crude oil supplies improve our net export position substantially; net exports reach a level of about 69 thousand cubic metres per day by 2005.

Trade in oil products resulted in small net exports in 1987. In both

cases, rising product imports occur because demand exceeds Canadian refinery capacity, resulting in modest net imports by 2005. Thus, in the low case, net total import positions (crude oil and products) are somewhat higher than those for crude oil alone. In the high case, rising net imports of products result in net total exports less than those for crude oil alone (Table 7-14).

7.10 Concluding Comments

We conclude this chapter with a brief description of the major crude oil pipeline systems in Canada and the impact that our projected crude oil supply/demand balances could have on their operation.

Trans Mountain Pipe Line Company Ltd. (Trans Mountain) and Interprovincial Pipe Line Company, a Division of Interhome Energy Inc. (Interprovincial), operate the two major pipeline systems through which Canadian crude oil is moved to domestic and export markets. The Portland-Montreal pipeline also plays an important role in the delivery of offshore crude oil to Montreal refineries. The location of these pipelines is shown on Figure 7-11.

Trans Mountain operates a pipeline for the shipment of crude oil, partially processed oil and refined petroleum products from receipt points in Alberta and British Columbia to delivery locations in British Columbia, principally the four refineries in the Vancouver area. The Westridge marine terminal in Burnaby is used to accommodate shipments by tanker of light and heavy crude oils to offshore markets. Trans Mountain also operates a lateral pipeline from Sumas, B.C. to Anacortes, Washington where four refineries are located. Although these refiners depend primarily on Alaskan North Slope crude oil, they take Canadian crude oil when it is priced competitively. While crude oil constitutes a large portion of Trans Mountain's throughput, volumes of refined petroleum products (gasoline and diesel) for delivery to product terminals at Kamloops, B.C. have been increasing since

Table 7-14

Exports and Imports of Crude Oil and Products

(Thousands of Cubic Metres per Day)

Low Case	1987	1990	1995	2000	2005
Exports					
Light	44	35	14	7	7
Heavy	56	61	37	34	39
Subtotal Crude Oil	100	96	51	41	46
Products	27	35	34	34	34
Total	**127**	**131**	**85**	**75**	**80**
Imports					
Light	58	69	70	80	95
Heavy	7	7	7	7	7
Subtotal Crude Oil	65	76	77	87	102
Products	23	24	38	42	50
Total	**88**	**100**	**115**	**129**	**152**
Net Crude Oil and Products Exports (Imports)	39	31	(30)	(54)	(72)

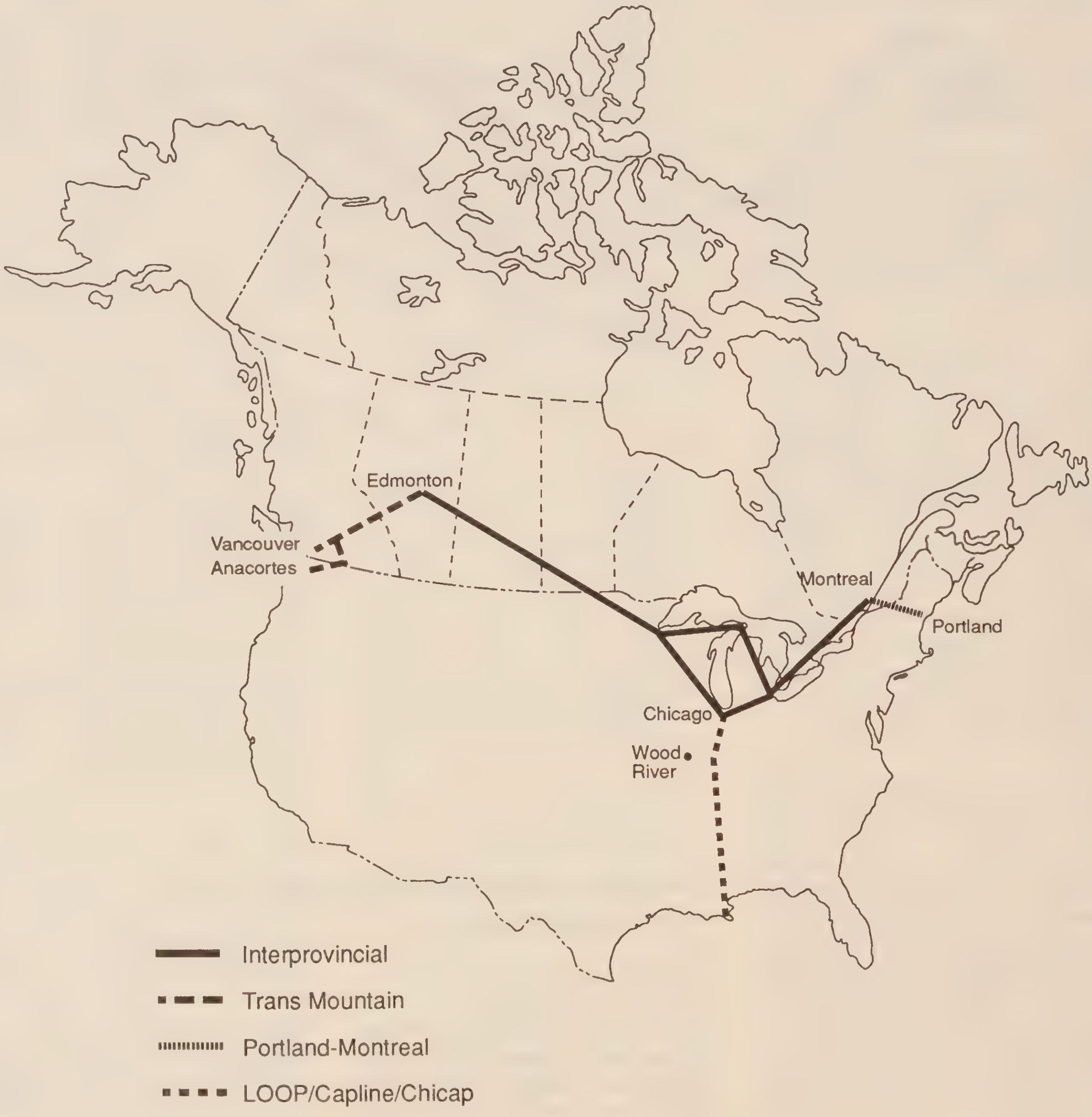
High Case	1987	1990	1995	2000	2005
Exports					
Light	44	42	15	27	22
Heavy	56	79	105	98	98
Subtotal Crude Oil	100	121	120	125	120
Products	27	34	33	33	33
Total	**127**	**155**	**153**	**158**	**153**
Imports					
Light	58	69	56	44	44
Heavy	7	7	7	7	7
Subtotal Crude Oil	65	76	63	51	51
Products	23	20	31	41	50
Total	88	96	94	92	101
Net Crude Oil and Products Exports (Imports)	39	59	59	66	52

Note: The numbers in this table have been rounded.

Source: Appendix Table A7-17

Figure 7-11

Major Crude Oil Pipelines



their commencement in 1985. On average, the pipeline shipped 26 thousand cubic metres per day of crude oil and products in 1987, of which 22 thousand cubic metres per day was shipped to domestic locations and 4 thousand cubic metres per day was transported to export destinations.

For both cases, we expect domestic feedstocks shipped via Trans Mountain to continue to meet British Columbia's requirements. In the high case, heavy crude oil tanker shipments from the Westridge dock, which have been made on a fairly regular basis since January 1987, are likely to continue and increase upon completion of Trans Mountain's expansion in 1990. In the low case, occasional deliveries could occur; however sufficient demand is likely to exist in the Northern Tier market to absorb surpluses.

Interprovincial operates the largest and most complex crude oil pipeline system in North America stretching over 3 700 kilometres from Edmonton, Alberta to Montreal, Quebec. The system transports as many as 35 different grades of petroleum including petroleum products, natural gas liquids and light, medium and heavy crude oils for about the same number of shippers.

Interprovincial delivers to locations in the Prairie provinces and to refining centres in Sarnia, Toronto and Nanticoke, Ontario; Montreal, Quebec; the Minneapolis-St. Paul area of Minnesota; Superior, Wisconsin; the Chicago area of Illinois and Indiana; Detroit, Michigan; Toledo and Canton, Ohio; and the Buffalo, New York area.

During 1987, average throughput was about 213 thousand cubic metres per day; 128 thousand and 85 thousand cubic metres per day were delivered respectively to domestic and export locations.

A major problem for the pipeline system since late 1984 has been, for the most part, a lack of adequate capacity to move shippers' tendered volumes despite having completed a number of facility expansions in the past few years.

Whether additional capacity will be needed on Trans Mountain or Interprovincial in the future will depend on the availability of crude oil and equivalent. The high case suggests expansion would be required but in the low case it is difficult to envisage the need for any expansion given the projected decline in supply. In fact, in the low case, deliveries of light crude oil to Montreal would cease by 2000 and there would be a need to import crude oil into Ontario beyond 2000.

However, if governments were to ensure that certain major projects proceed, the supply could be larger than shown in our low case. Additional east coast offshore supply and synthetic crude oil supply would reduce the need for imports in eastern Canada and the latter project would increase deliveries of light crude oil through the Interprovincial pipeline by 12 thousand cubic metres per day which would be sufficient to keep on supplying Ontario from western Canada beyond 2000. If further discoveries in the Mackenzie-Beaufort area were to lead to the construction of a crude oil pipeline from the Mackenzie Delta bringing forth an additional 24 thousand cubic metres per day, there would be no need to import into Ontario during the projection period. The impact of these projects on Quebec would be to extend the time during which domestic light crude could be delivered to Montreal refineries, but in the low case, these deliveries would be expected to cease by 2005.

If such developments were not forthcoming, Ontario's requirements could be met by increased flows through the Portland-Montreal system in conjunction with a reversal of the Sarnia-Montreal pipeline. Alternatively, foreign crude could be shipped from the Louisiana Offshore Oil Port (LOOP) to Chicago via the Capline and Chicap pipelines and then to Ontario on the Lakehead portion of the Interprovincial pipeline.

The Portland-Montreal pipeline transports offshore crude oil from South Portland, Maine to Montreal. Refineries in Montreal also receive domestic crude oil through the Interhome system so that the Portland-Montreal pipeline operates well below its 30 thousand cubic metre per day capacity. If domestic light crude oil supply were to decline as projected in the low case, Montreal and Ontario refiners would have to rely increasingly on imports. Should Ontario refiners import crude oil through a reversed Sarnia-Montreal pipeline, there would be a need to increase capacity on the Portland-Montreal system.

With respect to production of crude oil from the Mackenzie Delta and the Beaufort Sea area, which is projected to occur in the high case, new pipeline construction would be necessary to deliver this crude oil to the existing trunk line systems.

Chapter 8

Natural Gas Liquids

In this chapter we examine the extent to which natural gas liquids (NGL) - ethane, propane, butanes and pentanes plus - contribute to the supply of and demand for energy in Canada. We begin with a discussion of NGL supply from natural gas plants, crude oil refineries, and synthetic crude oil and heavy oil upgrading plants. This is followed by a review of domestic demand and a discussion of exports. The chapter concludes with supply/demand balances for each of ethane, propane and butanes. The pentanes plus supply/demand balance is part of the total supply/demand balance for light crude oil discussed in Chapter 7.

Historical production of NGL is shown in Appendix Table A8-1 and projected production in Appendix Table A8-2.

8.1 Natural Gas Liquids Supply

Our low and high case projections of NGL supply from *gas plants* are based on the corresponding projections of natural gas production discussed in Section 6.4, and on anticipated NGL yields (cubic metres of NGL produced per million cubic metres of natural gas production).

Production from currently producing natural gas pools is based on a plant by plant assessment of NGL supply, while production from non-producing pools and from reserves additions is based on assumptions about future NGL yields.

Throughout the 1960s and early 1970s yields of propane, butanes and pentanes plus increased. This is attributable to a number of factors:

- implementation of large gas cycling schemes in condensate reservoirs in order to maximize liquids recovery;
- increases in crude oil supply which boosted supply and processing of solution gas which is rich in NGL; and
- construction of reprocessing plant facilities (straddle plants) at Empress in 1964, Cochrane in 1970, and a second plant at Empress in 1971 which increased the recovery of liquids over that obtained from field processing plants.

However, by the mid-1970s the yields of these liquids began to decline as a result of declining production from the large gas cycling schemes in Alberta. Most affected was the yield of pentanes plus, much of which had historically been supplied from these schemes.

As yields of propane, butanes and pentanes plus began to decline in the 1970s, the extraction of ethane was just beginning. The yield of ethane has continued to increase as extraction facilities have been added and expanded at straddle plants, and more recently as a result of the addition of extraction facilities at field gas processing plants to meet the demand for liquids for enhanced oil recovery.

We expect that the trend to lower liquid yields will generally continue throughout the projection period as liquids in existing cycling schemes are depleted and as the share of solution gas in the total supply declines. However, the natural gas discovery at Caroline in Alberta, which is expected to be on full production by 1991, is rich in gas liquids and will slow this decline, as would other future major wet gas discoveries. Also, Mackenzie Delta gas production, which will be accompanied by large volumes of pentanes plus, leads to an increase in the overall yield of pentanes plus between 1999 and 2001.

The extent of future construction of field plant ethane extraction facilities will depend on the ethane policy adopted by the Alberta Government. We have not included any such facilities in our projections. However, the production of ethane is still expected to increase until the early 1990s as a result of increased natural gas throughputs at ethane extraction plants currently in operation. Historical and projected yields are shown for each NGL component in Figure 8-1 for the low case. Those for the high case are similar

because the assumed average natural gas composition is similar.

Given the yields, production of NGL from gas plants is directly related to the volume of natural gas produced. Because of the higher gas supply projections in this report as compared to our 1986 report (discussed in Chapter 6), our projections of related NGL production are much higher in the latter part of the projection period than was the case in our 1986 report.

Frontier gas and oil projects were discussed in Chapters 6 and 7. Of these projects natural gas production from the Mackenzie Delta and from the east coast offshore is expected to contribute to the supply of NGL. We expect that Mackenzie Delta gas, which comes onstream in 1999 in both our low and high cases (see Section 6.4), will be processed to recover pentanes plus. Production of pentanes plus from the Delta is projected to increase from 1800 cubic metres per day in 1999 to 4000 cubic metres per day by 2001, where it remains to the end of the projection period. We also anticipate that this gas will be stripped further of liquids in one of the straddle plants in Alberta.

East coast offshore gas production commences in 2004 in our high case (see Section 6.4) and reaches a peak level of 250 petajoules per year in 2005. Production of propane, butanes and pentanes plus corresponding to this level of natural gas production are projected at 750, 600 and 2500 cubic metres per day respectively.

As seen in Figures 8-2, 8-4 and 8-6, NGL production remains relatively stable throughout the projection period as declining yields are offset by increased natural gas production.

Ethane production is higher in the high case than in the low in the middle years of the projection period because of the processing of higher volumes of natural gas at straddle plants. However, by 2005, production is at capacity at several plants and ethane production is projected to be the same in both cases (Figure 8-3).

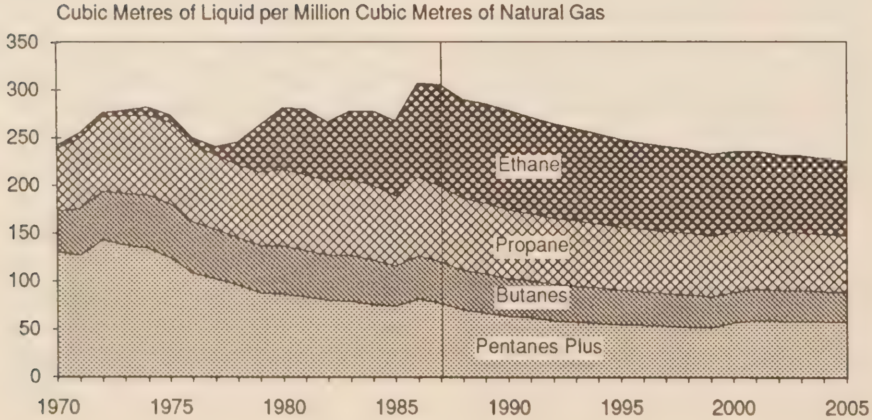
For propane, butanes and pentanes plus, the slightly higher levels of production in the high case correspond to higher levels of natural gas production. For pentanes plus, production of relatively large volumes associated with east coast natural gas production, in the high case only, contribute to the difference. The low and high case projections for propane and butanes are compared in Figures 8-5 and 8-7 respectively.

Detailed projections of field plant production for each NGL component from producing pools are provided in Appendix Tables A8-3 through A8-6. We assume these to be the same in both cases because most producing natural gas pools are fully developed, so that production of natural gas and NGL is the same in both cases. Projections of straddle plant production and production from currently non-producing reserves and reserves additions are different in the two cases reflecting the different levels of natural gas production.

Propane and butanes (LPG) are produced at *oil refineries* during various stages of the refining process. Crude oil entering refineries can contain as much as four percent LPG by volume. LPG are separated along with light gases from the other components of the crude oil stream at the beginning of the refining process and are also produced as a by-product of later stages of the refining operation.

Once recovered in a refinery, LPG is either marketed, consumed as fuel, used as feedstock to other processing units, or in the case of normal butane, blended with gasoline. Our projections of LPG supply

Figure 8-1
NGL Yields
Low Case



from refineries include only those volumes which we expect to be marketed. The projections are based on the volumes of LPG marketed per unit of crude oil feedstock on a regional basis in 1987 and on the projections of crude oil feedstock requirements discussed in Chapter 7. Although we recognize that the volume of refinery LPG marketed may change as the quality of crude oil refined in Canada varies or as refinery configurations are altered to meet changing product demands, our projections do not take these possibilities into account.

As shown in Table 8-1 refinery production of propane and butanes is essentially the same in both cases and increases only moderately over the projection period.

The projections of propane and butanes supply from refineries are shown by region in Appendix Tables A8-7 and A8-8 respectively for the low and high cases.

Our supply projections do not include any production of NGL from *synthetic crude oil or upgrading plants.* Currently the synthetic gases generated in the upgrading processes at these plants along with any liquids they contain are used as plant fuel. Plant owners have studied the recovery of NGL from synthetic gases but to date they have not found it economic. We assume that the new synthetic oil and upgrading plants in our projections will not include natural gas liquids recovery units.

8.2 Domestic Demand

NGL have a wide variety of uses in Canada. Since the construction of the first world scale ethylene plant in Alberta in 1978, ethane has been an important petrochemical feedstock. A second plant was constructed in 1984 and our projections include a third ethylene plant in 1995. Petrochemical demand for ethane is projected at 21 thousand cubic metres per day in 1995.

Ethane is also used for enhanced oil recovery.[1] As Figure 8-2 shows, the use of ethane in enhanced oil recovery has increased appreciably since 1984 with the start of several miscible flood projects; it currently accounts for about 55 percent of the NGL used in miscible floods. Ethane requirements for miscible floods (after allowing for reproduced quantities) are projected to increase in the near term but decline to 0 by 2000 in the low case and by 2003 in the high. Ethane requirements in the high case exceed those of the low case in the near term because of the greater number of hydrocarbon miscible projects assumed to come on stream if oil prices are relatively high. In the longer term, ethane demand is dominated by petrochemical requirements.

Table 8-1

Supply of Natural Gas Liquids

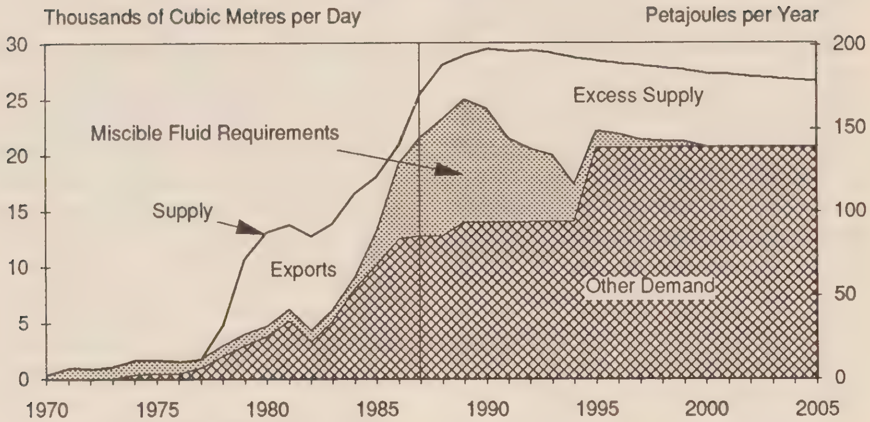
(Thousands of Cubic Metres per Day)

	1987	1995		2005	
		Low Case	High Case	Low Case	High Case
Gas Plants					
Ethane	25.5	28.4	29.3	26.6	26.6
Propane	19.1	20.5	21.9	20.1	21.3
Butanes	10.5	11.2	12.0	10.7	11.5
Pentanes Plus	18.6	17.1	18.2	19.7	22.5
Refineries					
Ethane	-	-	-	-	-
Propane	3.9	4.2	4.2	4.3	4.3
Butanes	3.5	3.8	3.8	3.8	3.9
Pentanes Plus	-	-	-	-	-
Total					
Ethane	25.5	28.4	29.3	26.6	26.6
Propane	23.0	24.7	26.1	24.4	25.6
Butanes	14.0	15.0	15.8	14.5	15.4
Pentanes Plus	18.6	17.1	18.2	19.7	22.5

Source: Appendix Table A8-2.

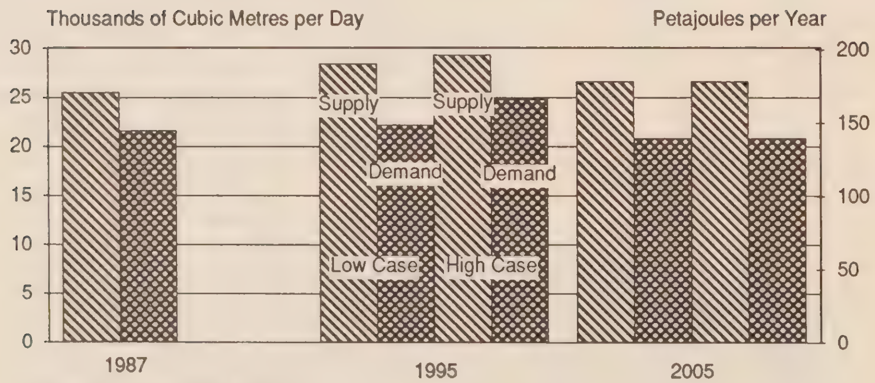
1. Our projections of ethane, propane and butanes requirements for miscible floods are net requirements after accounting for volumes expected to be reproduced from current and future hydrocarbon miscible flood projects. Reproduced quantities are adequate to satisfy NGL requirements for miscible floods by 2000 in the low case and by 2003 in the high.

Figure 8-2
Ethane Supply and Demand
Low Case



Source: Appendix Tables A8-1 and A8-9.

Figure 8-3
Ethane Supply and Demand
Comparison of Low and High Cases



Source: Appendix Table A8-9.

Traditional markets for propane have included residential space heating, agricultural uses such as crop drying and powdered milk production, restaurant fuel in the commercial sector, portable heating in the industrial sector, and use as a solvent for enhanced oil recovery. Since the late 1970s larger volumes of propane have been used as a petrochemical feedstock (see Section 4.1.5). During the early 1980s a market developed for propane as a road transportation fuel.

We project low case propane demand to increase in all end use sectors, but particularly in the transportation and petrochemical sectors. Demand in the transportation sector increases from 2 thousand cubic metres per day to 2.7 thousand cubic metres per day in 2005. Over the same period, petrochemical demand increases from 1.4 thousand to 3 thousand cubic metres per day. Propane requirements for miscible floods (net of reproduced quantities) remain constant in the near term and then fall to zero by the year 2000.

In the high case slightly larger increases in demand occur as a result of greater propane use in transportation (Figure 8-5). Petrochemical demand is the same in both cases. Propane demand for miscible floods is higher in the near term than in the low case as a result of higher crude oil reserves additions attributed to miscible floods.

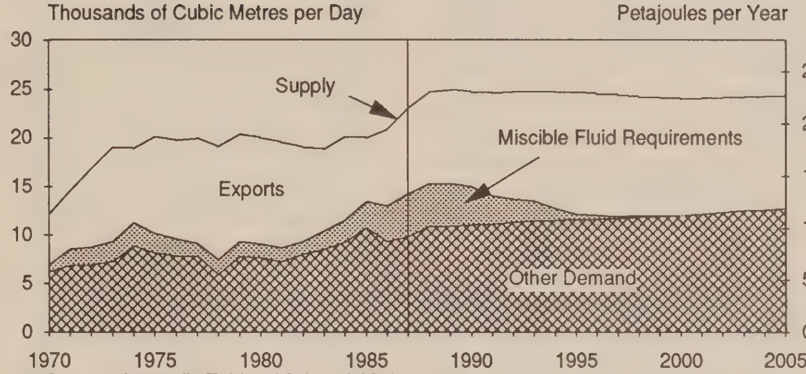
Butanes are used primarily as a refinery feedstock but are also used as petrochemical feedstocks and to a very limited extent for space heating. Butanes are seldom used in miscible floods except when they are entrained in NGL mixes.

The major factor influencing refinery demand for butanes is motor gasoline production. Refinery demand for butanes is dominated by demand in Alberta and Ontario. Gasoline production in Alberta declines over the projection period but it increases in Ontario. We assume that because most refineries blend the maximum volumes of butanes permitted in gasoline, changes in the production of gasoline lead to corresponding changes in the demand for normal butane.

The demand for butanes may also be affected by legislated reductions in the use of lead (which acts as an octane enhancer) in motor gasoline. The need to meet octane requirements from alternatives to the addition of lead could lead to increased demand for butanes feedstocks for conventional refinery processes or for the production of methyl tertiary butyl ether (MTBE) which can be blended in gasoline to increase octane. We have not, however, assumed that refinery feedstock requirements will increase for this purpose, nor have we included any MTBE production in our projections. Refinery requirements for butanes exceeding refinery production are met from purchases of gas plant butanes.

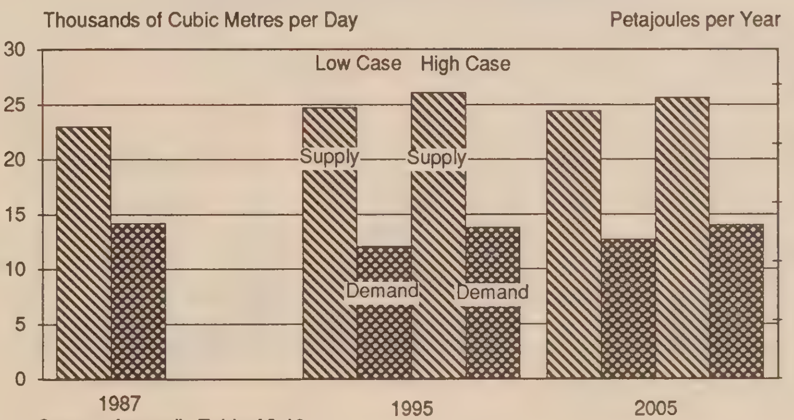
The demand for butanes in the category entitled "other demand" on Figure 8-6 includes refinery and end use requirements. Refinery requirements for butanes remain at a level of about three thousand cubic metres per day throughout the projection period in both cases. Petrochemical demand increases over the projection period from 0.4 thousand to 0.7 thousand cubic metres per day in both cases. The demand for butanes as a miscible fluid is projected to remain level until 1990,

Figure 8-4
Propane Supply and Demand
Low Case



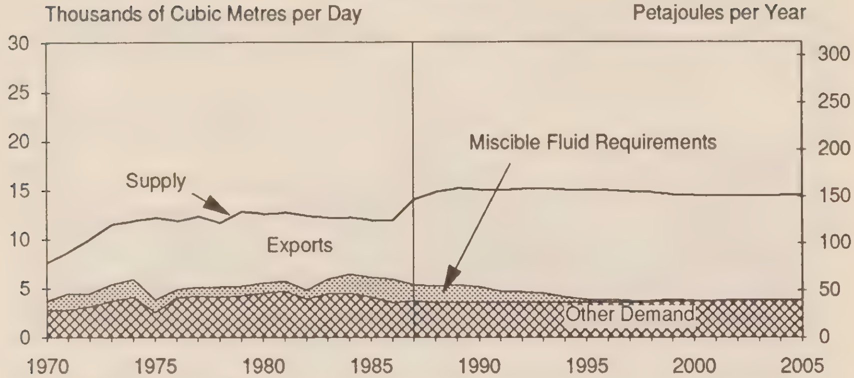
Source: Appendix Tables A8-1 and A8-10.

Figure 8-5
Propane Supply and Demand
Comparison of Low and High Cases



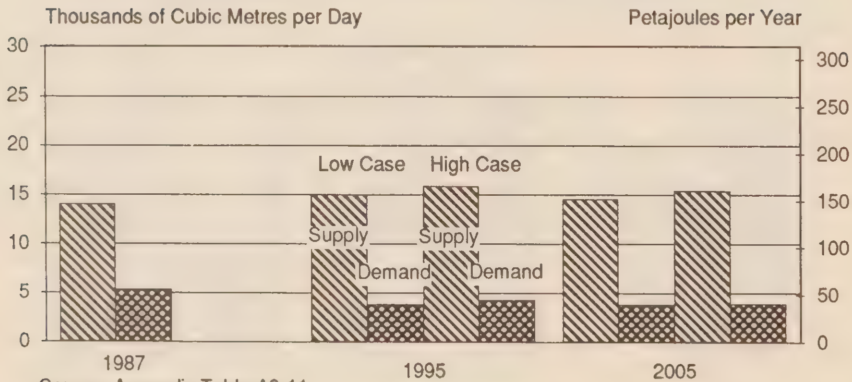
Source: Appendix Table A8-10.

Figure 8-6
Butanes Supply and Demand
Low Case



Source: Appendix Tables A8-1 and A8-11.

Figure 8-7
Butanes Supply and Demand
Comparison of Low and High Cases



Source: Appendix Table A8-11.

after which, as with the other gas liquids, it declines to zero by 2000 and 2003 in the low and high cases respectively.

To cope with the seasonal nature of the supply and demand for propane and butanes, large underground storage caverns dissolved from salt formations have been developed. These facilities are concentrated in Alberta and Saskatchewan and in the Sarnia-Windsor, Ontario area. The IPL system is the major carrier of NGL from western Canada to Sarnia where liquids are fractionated into their product components. The Cochin pipeline from Edmonton to Sarnia can also move NGL to eastern Canadian and U.S. markets. Onward deliveries from Sarnia are made by pipeline, rail and road transport.

Southern Saskatchewan and Manitoba are served by the Petroleum Transmission Company pipeline from Empress, Alberta to Winnipeg, Manitoba.

8.3 Exports

The United States currently represents Canada's only export market for propane and butanes. Canada exported propane to Japan in the past, but no longer does so because Middle East and other Pacific Rim countries have a competitive advantage.

The U.S. Midwest is Canada's main export market because of an existing pipeline and storage infrastructure. This market lends itself well to Canadian-sourced supplies because, unlike the U.S. Atlantic and Gulf Coast markets, it is difficult to serve with offshore supplies. Propane originating in Alberta is transported to U.S. Midwest markets via the Cochin and MAPCO pipeline systems. In

addition, NGL mixes are transported via the IPL system to Sarnia, Ontario, where they are fractionated and exported to U.S. customers, located in the Midwest and North Central and North Eastern U.S. Western Canadian supplies destined for export from Eastern Canada are supplemented with local refinery produced propane and butanes.

On the U.S. Gulf Coast, where increased competition is expected from Middle East-sourced supplies, notably Algerian, Canadian propane is today competitive owing to incentive tariffs on both the Cochin and the MAPCO systems.

We expect that growing U.S. markets will continue to absorb Canada's propane and butanes surpluses.

No volumes of ethane are now being exported: however, ethane exports occurred from 1978 to 1986. Surplus production, when it occurs, is instead reinjected into the natural gas stream.

8.4 Concluding Comments

Since the mid-1970s production of NGL has exceeded domestic requirements and large quantities have been exported. Our projections[1] (Figures 8-2 to 8-7) show that the quantities of propane and butanes available for export will increase until the mid-1990s and then decline slightly during the projection period.

For ethane, demand for both miscible floods and for petrochemical feedstock has increased sharply in recent years. Our projections show a fairly constant demand for ethane. Ethane demand for petrochemical feedstock increases, while that for miscible floods decreases (after allowing for reproduced quantities). Although we have shown surplus production of ethane throughout the projection period we do not anticipate any exports. Any production exceeding demand will most likely be reinjected into the gas stream and marketed as natural gas.

End use demand for propane has been increasing steadily since the late 1970s. Our projections show this trend continuing, mainly due to growth in petrochemical and transportation uses. Requirements for hydrocarbon miscible floods are projected to decline (after allowing for reproduced quantities) resulting in a decline in total demand for propane until the mid-1990s. Supply is projected to be relatively level in the low case and increase modestly in the high case, resulting in substantial surpluses of propane available for export, a situation which has existed since the late 1960s.

Demand for butanes has been relatively stable since the early 1970s, at levels far below that of production. Our projections show end use plus refinery requirements for butanes continuing to be relatively stable but requirements for miscible floods declining in the 1990s.

Supply of butanes is projected to increase in the near term and then stabilize, leading to an even greater excess of supply over demand in the future than that experienced in the past.

---

1. Details on supply and demand for ethane, propane and butanes are provided, by year, in Appendix Tables A8-9 to A8-11.

Chapter 9

Coal

In this chapter we examine the extent to which coal is likely to contribute to the supply and demand for energy in Canada. The discussion begins with a review of the various types of coal, their uses and the resources and reserves attributable to each type. There follow sections on coal prices and transportation costs, domestic demand, exports and production and imports.

Canada has extensive and diverse coal resources about 98 percent of which are in western and northern Canada (Appendix Table A9-2). These range from the lignitic and subbituminous classes (often called "soft coal") through to bituminous coal and anthracite, the highest quality types of "hard coal":

- Lignitic and subbituminous coals are currently used mainly for thermal power generation close to the mine mouth. Some deposits could also prove suitable as feedstocks for coal gasification or liquefaction plants.
- Bituminous coals are also used for thermal power generation, and their higher quality makes it worthwhile to transport these coals to distant markets. Some bituminous coals can also be used to produce coke, a reducing agent and heat source for steelmaking and other metallurgical industries.
- Anthracitic coals can be used for domestic heating and for special applications such as titanium smelting. They can also be blended with bituminous coals to improve the coking quality for industrial uses.

An important characteristic of coal is sulphur content. Reduced acid gas emissions are essential to continued acceptability of coal. Increasing concern over sulphur dioxide emissions and acid rain place a premium value on western coal reserves which generally have less than one percent sulphur. Atlantic coals typically contain about four percent sulphur, with a few deposits containing ten percent or more. New technologies are under development to enable cleaner, safer and more economical mining, transportation and use of this resource.

The criteria used to classify coal are summarized in Appendix Table A9-1.

9.1 Resources and Reserves

Because the National Energy Board does not independently assess resources and reserves of coal, we adopted data from external sources for this report.

Coal resources are commonly divided into two main categories: resources of "immediate interest" and resources of "future interest". To be of immediate interest, resources must consist of coal seams with combinations of thickness, quality, depth and location which render them attractive for continuing exploration or early development. Resources of future interest are generally in very remote areas or areas in which recovery would be very costly with conventional technologies. Both categories are subdivided into "measured", "indicated", and "inferred" resources, according to the amount of exploration, sampling and analysis that has been done. There is least assurance about inferred resources.

The portions of the measured and indicated resources that are the most suitable and likely for commercial development are called reserves. Reserves are deposits that have been adequately delineated through exploration and sampling and which can be considered economic for mining using current technology. Coal reserves amount to only two percent of the total resource.

Table 9-1 shows the portion of reserves that are recoverable, after allowing for mining losses. Reserves are higher than those reported in our 1986 report because of the addition of reserves associated with the McLeod River and Mercoal mining projects in the Foothills region of Alberta. The ERCB has granted development permits for both of these projects.

Table 9-1

Remaining Recoverable Reserves of Coal by Province and Class at 31 December 1985

Province	Class	Megatonnes	Petajoules
British Columbia	Lignitic	566	7600
	Bituminous		
	Thermal	433	10836
	Metallurgical	1563	39114
Alberta	Subbituminous	871	15800
	Bituminous		
	Thermal	800	17115
	Metallurgical	240	5135
Saskatchewan	Lignitic	1670	23000
New Brunswick	Bituminous		
	Thermal	21	500
Nova Scotia	Bituminous		
	Thermal	300	7663
	Metallurgical	115	2937
Canada	Lignitic	2236	30600
	Subbituminous	871	15800
	Bituminous		
	Thermal	1553	36114
	Metallurgical	1918	47186
	Total	6578	129700
Canada	Thermal[a]	4660	82514
	Metallurgical	1918	47186

Note: [a] Thermal includes all lignitic, subbituminous and thermal bituminous reserves.

Source: Coal Mining in Canada: 1986, Report 87-3E, CANMET, September 1987.

Total remaining recoverable reserves of 6578 megatonnes are more than 100 times Canada's 1987 production of 61 megatonnes. Of these reserves, 71 percent consists of thermal coal.

9.2 Coal Prices and Transportation Costs

Coal prices have declined by about 30 percent in real terms since 1982 mainly as a result of an oversupply of coal on world markets. In recent years China, Columbia and Venezuela have emerged as new low cost suppliers and this has contributed to depressed coal prices. The coal industry is expected to remain highly competitive keeping future price increases to a minimum.

The costs of producing and transporting coal to export markets vary widely depending on the country of origin and the export market. For example, China can supply thermal coal markets in Asia at a significantly lower cost than can Canada, in part because of the lower transportation costs incurred. We have conducted our analysis on the assumption that prices paid to Canadian producers will be sufficient to allow moderate increases in exports. Because Canada is generally a high cost supplier, our export values may be dependent on the extent to which buyers wish to maintain a diversity of supply sources to improve security of supply.

In 1987, the selling price of metallurgical coals at Canadian export points was in the range of $C 60 to 90 per tonne (about $C 2.00 to 3.00 per gigajoule); the price of thermal coals for export was in the range of $C 42 to 46 per tonne (about $C 1.50 per gigajoule). In early 1988, most producers negotiated price increases but for export contracts denominated in U.S. dollars, devaluation of the U.S. dollar has largely offset these price increases.

We are projecting that domestic coal prices for electricity generation and at the industrial burner tip will be unchanged in real terms, even as we mine lower quality reserves in the future. This is based on the view that the past trend of productivity increases will continue. Coal producers are conducting or supporting research to improve mine productivity. For example, a process called oil agglomeration is entering commercial use as a means of recovering fine coal particles which are now discarded.

With the exception of coal used for mine site electricity generation, markets for western Canadian coals involve long rail hauls, the cost of which accounts for a large part of

the delivered price. Thus transportation costs affect our ability to compete in export markets, and with U.S. coal in Ontario. Figure 9-1 shows the principal mines, rail routes and coal shipping terminals in Canada. Western coals exported through ocean terminals in British Columbia are hauled about 1100 kilometres; coals moving east to Great Lakes bulk shipping terminals at Thunder Bay cover about 2200 kilometres. Rail charges average about $C 21 per tonne for coals moving to west coast ports and up to $C 36 per tonne for shipment east to Thunder Bay.

Because the costs of inland transportation are a large component of the delivered cost of western coals, research projects aimed at lowering transportation costs are underway:

- Upgrading of coals to remove noncombustible matter and excess moisture prior to shipment is one area of research.
- Canadian railway companies and the Alberta government are studying the design and operation of unit coal trains with the aim of further increases in efficiency.

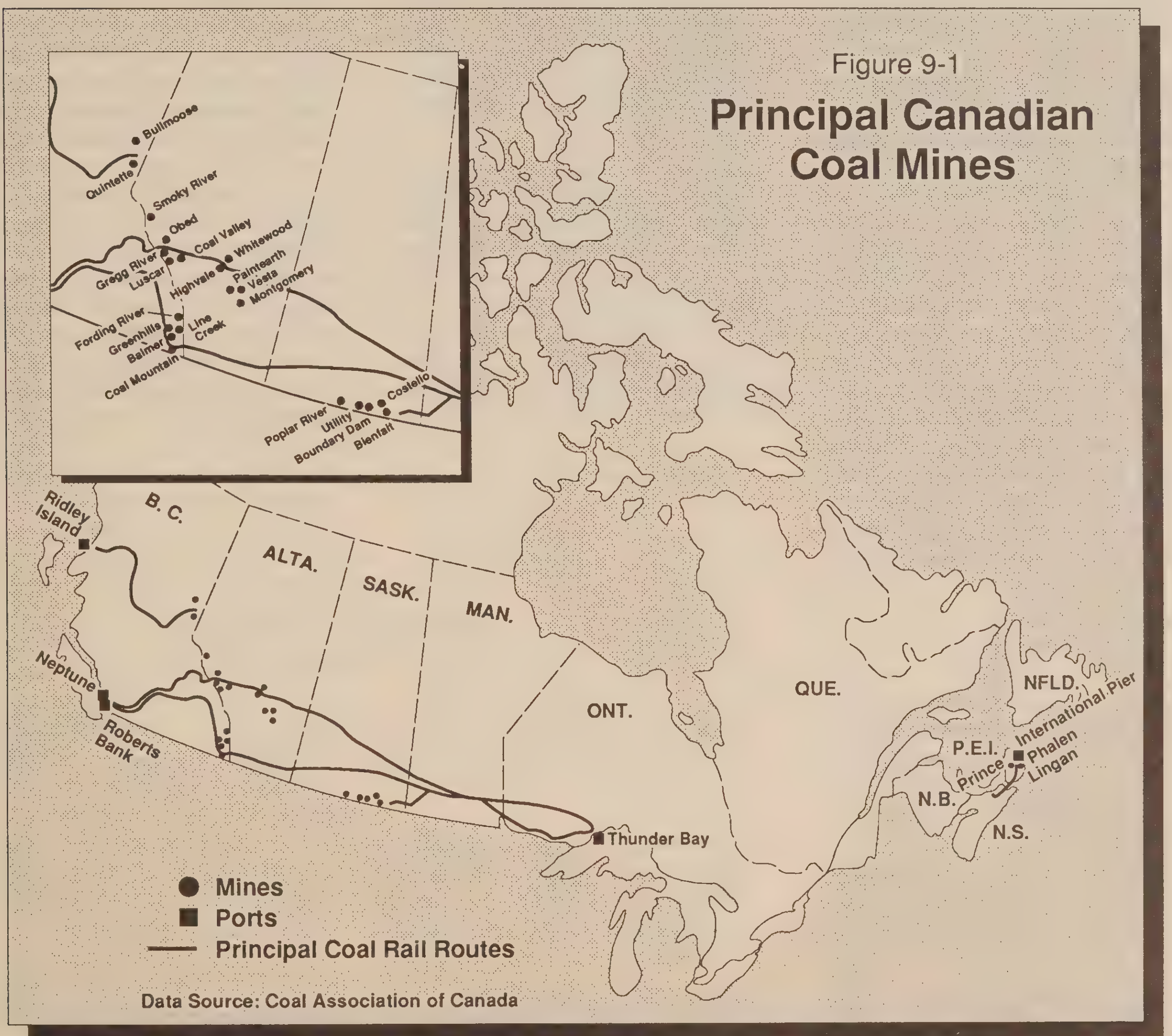


Figure 9-1
Principal Canadian Coal Mines

- In cooperation with West Germany, Canada is assessing the combustion of coal-water fuels; pipelining coal-water mixtures could reduce transportation costs.

- The feasibility of pipelining coal-oil mixtures is also being studied.

9.3 Domestic Demand

For the first half of this century, coal was the major source of energy in Canada; it accounted for 49 percent of primary energy demand in 1950. During the 1950s and 1960s oil and natural gas displaced coal used for space heating and in general industry and the railways converted from coal to diesel fuel. In the 1960s increased use of coal in Ontario by the steel industry and for electricity generation reversed the decline in demand. Expansion in coal demand since 1970 has been primarily for electricity generation in Alberta, Saskatchewan and Nova Scotia. Currently the main uses of coal in Canada are for the generation of electricity (thermal coal) and for the fabrication of iron and steel (metallurgical coal) (Table 9-2). Research is continuing on the conversion of coal to other fuels.

Thermal Coal

Alberta, Saskatchewan and Nova Scotia are expected to continue to favour coal for power generation, with emissions control devices added as required. As discussed in Chapter 5, Ontario's requirements for coal to generate electricity are projected to decline until the mid-1990s, as new nuclear capacity (now under construction) replaces existing thermal generation. However, Ontario Hydro has not yet committed itself to an expansion plan for the 1995 to 2005 period. We have assumed that Ontario Hydro will not build any new coal-fired plants during the projection period. Ontario Hydro's decision on the use of coal versus nuclear generation will be affected by Ontario legislation which has imposed a sulphur dioxide emissions ceiling for 1994 and beyond. Stricter emission standards could be met by installing pollution reduction equipment in coal burning plants, by burning low sulphur coal, by using less coal, or by moving to fluidized bed combustion units. Meeting more stringent emission standards will likely mean that generation cost per kilowatt hour will be higher than that implied by today's relatively low prices for medium sulphur coal.

Fluidized bed combustion systems and integrated gasification, combined cycle, power plants are new technologies which have the potential to be more effective in terms of both environmental control and power costs than existing plant technology. Federal funding was used to construct a 20 MW circulating fluidized bed demonstration boiler at New Brunswick Electric Power Commission's Chatham generating station which was completed in late 1986. This technology is being considered for future construction of coal-fired generating stations in the Atlantic region, where indigenous coals have relatively high sulphur content.

The cement industry is currently the largest user of thermal coals in the industrial sector, followed by the smelting and refining industry. In Alberta, the use of coal to generate steam used for in situ recovery of bitumen in place of natural gas is being reviewed and could provide a new market for western coal. Based on our projections of bitumen production contained in Chapter 7, a potential market of up to 17 megatonnes of subbituminous coals could exist in Alberta by the year 2005. In the high case natural gas prices are projected to be sufficiently high to allow coal to penetrate only part of this market beginning in the mid-1990s. In this

Table 9-2
Domestic Coal Demand
(Megatonnes)

	1986[a]	1995[b]		2005[b]	
		Low Case	High Case	Low Case	High Case
Thermal					
Electricity	36.4	38.9	46.0	50.2	61.2
Other	2.0	3.3	5.6	3.7	12.8
Total	38.4	42.2	51.6	53.9	74.0
Metallurgical	6.1	8.3	9.2	10.5	12.3
Total	44.5	50.5	60.8	64.4	86.3

[a] Source: Statistical Review of Coal in Canada: 1987, Energy, Mines and Resources, 1988.
[b] Source: Appendix Table A9-4.

case, demand for subbituminous coal for steam raising grows from 2 megatonnes in 1995 to 9 megatonnes in 2005. No coal use is provided for in the low case. This accounts for most of the difference between the low and high cases in the other thermal category in Table 9-2.

Metallurgical Coal

Demand for metallurgical coals is determined mainly by the demand for coke in steelmaking. We expect that as a result of improved efficiency in the use of coke to produce finished steel, the demand for coke will grow more slowly than the growth in the output of the iron and steel industry.

Coal Conversion

Among the new technologies with potential longer term impact on domestic demand, co-processing of coal and heavy oil may provide an economically viable means of producing liquid fuels from coal. Ontario-Ohio Synthetic Fuels Corporation is proceeding with a 1900 cubic metre per day upgrader project in Ohio which will co-process 600 tonnes per day of Ohio coal and 1400 cubic metres per day of heavy crude oil into naphtha and middle distillates. In a recent report[1] the supply cost for coal/oil co-processing was estimated at $C 230 per cubic metre in 1986 dollars. The costs for direct liquefaction processes were higher at 280 and 340 dollars per cubic metre for two stage and single stage processes respectively. Based on these costs and given our oil price projections only coal/oil co-processing could be economic in the latter part of the projection period in our high case. However, this is an emerging technology and we have not included in our projections any demand for coal for use in coal/oil co-processing.

9.4 Exports

As recently as 1950, coal accounted for over 60 percent of world primary energy requirements. Seaborne trade in coal was virtually non-existent and most land trade was restricted to contiguous countries.

Between 1950 and 1973, the year of the first international oil price shock, the relative importance of coal progressively diminished as the use of oil and natural gas expanded. By 1973, coal supplied only 31 percent of world primary energy demand and its use was confined essentially to electricity generation, steel production and some other industrial markets. However, in absolute terms, demand for coal had increased by over 50 percent between 1950 and the mid-1970s. China and the U.S.S.R. accounted for most of this increase.

During the period from 1973 until mid-1986 coal had a price advantage in the growing electricity generation market and its use expanded at the expense of oil. World-wide, the major steel producing countries, the U.S. and Japan, lost market share to new steel producing countries, notably, South Korea, Taiwan and Brazil. Unlike the U.S., these countries are dependent on coal imports.

In recent years, world trade in metallurgical coals has been relatively stable at about 160 megatonnes. However, trade in thermal coals, estimated at 178 megatonnes in 1987, has grown at an average rate of 6.6 percent per year since 1980. Japan accounted for 42 percent of world metallurgical coal imports in 1987, and about 14 percent of all imports of thermal coals.

The world coal industry experienced large capacity increases in recent years which, combined with a stabilization in world demand for metallurgical coal, resulted in excess productive capacity, leading in turn to intense competition among coal exporters. The oversupply situation was eased in 1987 by the closure of several mines with high production costs in Australia, South Africa and the United States.

The Canadian coal exporting industry was developed in Alberta and British Columbia during the late 1960s and early 1970s to serve Japanese metallurgical coal markets. Large export contracts with Japanese steelmakers led to the opening of new mines and in 1970, construction of a bulk shipping terminal at Roberts Bank near Vancouver.

By 1983 Canadian coal exports reached 17 megatonnes, 15 megatonnes metallurgical and 2 megatonnes thermal. In 1984, exports jumped by 50 percent as a result of export contracts for coal from new mines in Alberta and northeastern British Columbia. Since 1984, coal exports have been in the neighbourhood of 26 megatonnes, more than 80 percent of which was metallurgical coal. These exports were facilitated by development of a second west coast port at Ridley Island, near Prince Rupert, and additional rail facilities in northern British Columbia. Bulk shipping facilities at Roberts Bank and

1. *An assessment of the Potential for Coal-Derived Syncrudes in Canada,* Study No. 27, Canadian Energy Research Institute, June 1988.

Ridley Island are capable of moving 22 and 12 megatonnes per year respectively. The bulk shipping facility at Thunder Bay, used to serve both domestic and U.S. markets, has an annual capacity of six megatonnes.

Internationally, in 1987, about 14 percent of the metallurgical coal exports and 3 percent of the thermal coal exports originated in Canada. Table 9-3 provides a summary of international coal trade by province.

As can be seen in Table 9-4, Japan accounted for 64 percent of total Canadian exports, and South Korea 15 percent. Smaller volumes went to Brazil, the U.S., Europe, and other Latin American and Asian countries.

Metallurgical Coal

Almost 90 percent of Canada's metallurgical coal exports in 1987 were shipped to four countries: Japan, South Korea, Brazil, and the United States. Exports to Japan increased by almost 50 percent from 1983 to 1984 and peaked at over 17 megatonnes in 1985. Exports to South Korea have grown steadily in the 1980s and reached their highest level to date in 1987. Exports to Brazil in 1987 were up almost seven percent over 1986 levels. Exports to the U.S. have been growing steadily since 1980 but still remain a small proportion of total exports. In total, exports of metallurgical coals were up by 4.5 percent in 1987, just short of the peak level of 22.5 megatonnes attained in 1985. Canada's main competitors for metallurgical coal markets include Australia, South Africa, the U.S.S.R. and the U.S.

In projecting future coal exports, we assume that world trade in met-

Table 9-3

Coal Exports and Imports in 1987

	Megatonnes	Petajoules	Percent
Exports			
British Columbia	21.1	583.2	79
Alberta	5.1	141.3	19
Nova Scotia	0.5	13.5	2
Canada	26.7	738.0	100
Imports			
Ontario	13.6	395.4	95
Quebec	0.6	18.2	4
Nova Scotia	0.1	1.7	<1
Canada	14.3	415.3	100

Source: Statistics Canada, cat. no. 57-003.

Table 9-4

Coal Exports in 1987 by Destination

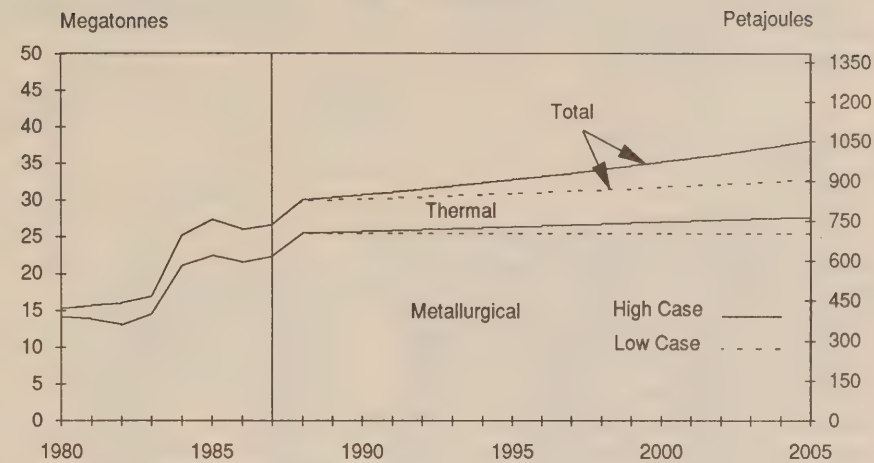
(Kilotonnes)

	Thermal	Metallurgical	Total
Japan	2038	15027	17065
South Korea	1148	2801	3949
Brazil	38	1195	1233
United States	102	763	865
France	230	370	600
Taiwan	-	565	565
Sweden	-	352	352
United Kingdom	-	334	334
Hong Kong	313	-	313
Denmark	302	-	302
Netherlands	20	258	278
Pakistan	-	217	217
West Germany	113	98	211
Portugal	-	207	207
Chile	-	153	153
Turkey	-	52	53
Italy	-	43	43
Total	4304	22436	26740

Source: Statistical Review of Coal in Canada: 1987, Energy, Mines and Resources, 1988.

allurgical coals will see only small growth. A 1988 report by the U.S. Department of Energy[1] estimates that world demand for metallurgical coal imports will grow modestly from 158 megatonnes in 1986 to 166 megatonnes by the year 2000 (mid-demand case). This low growth is attributed to slower growth in steel demand than in the past because of lower economic growth world-wide, increased use of lighter and stronger steel substitutes, and improved efficiency in the production of finished steel by increased use of continuous casting technology. In addition, electric furnace production of steel (which does not require coke) is expected to grow significantly. We project that in the low case Canada will be able to maintain exports at 25.5 megatonnes, the level projected for 1988. In the high case, Canadian exports are projected to escalate at 0.5 percent per year after 1988, resulting in growth from the current level of 22 megatonnes to 28 megatonnes in 2005.

Figure 9-2
Coal Exports



Source: Appendix Table A9-4.

These projections may be optimistic to the extent that the future of northeastern British Columbia coal production is in question. Development of high cost mines in this area in the early 1980s was based on long-term contracts with the Japanese when the outlook was for higher coal prices than currently exist or are anticipated. Current market prices are about two-thirds the price being paid for this coal. Consequently, the Japanese have requested Quintette Coal Ltd., the major northeastern B.C. coal producer, to reduce prices. Negotiations are still ongoing.

In developing our export projections we observed that to date the Canadian industry has been able to hold its market share in spite of a 30 percent drop in world metallurgical coal prices since 1982. This is attributable to productivity improvements at Canadian mines, resulting in lower unit production costs and, in the case of northeastern British Columbia production, to the receipt of higher than average world prices. We believe that most Canadian mines will be able to maintain their market positions, recognizing that this may require further improvements in productivity.

Thermal Coal

Japan and South Korea were the destination of almost three-quarters of Canada's thermal coal exports in 1987. Exports to South Korea were about the same as in 1986 but those to Japan were up eight percent. In total, exports of 4.3 megatonnes were less than the peak level of 4.9 megatonnes reached in 1985.

The outlook for growth of world trade in thermal coals is much more optimistic than for that in metallurgical coals as a result of the anticipated growth in requirements for electricity generation, particularly in the Far East and in Western Europe.

The U.S. Department of Energy report, referred to above, projects that world import demand for thermal coals will grow from 176 megatonnes in 1986 to 291 megatonnes in the year 2000 (mid-demand case).

Canadian producers, with high transportation costs and competition from countries such as South Africa, Australia and the new low cost producers (Colombia, China,and Venezuela) will have to market aggressively to share in this growth. Potential for increased exports to the U.S. to serve west coast industrial markets may also exist. We project Canadian exports to increase annually by three percent in our low case and five percent in the high case. Based on the DOE projections, this would lead to a slight decrease in our market share in the low case and a slight increase in the high case.

1. *Annual Prospects for World Coal Trade 1988*, Energy Information Administration, U.S. Department of Energy, April 1988.

Exports of thermal coal grow from 4.3 megatonnes to 7.3 megatonnes by 2005 in the low case and to 10.3 megatonnes in the high case (Figure 9-2).

9.5 Production and Imports

In 1987, 14 major companies operated 25 principal mines in Canada (Figure 9-1). These mines had the capacity to produce 43 megatonnes per year of thermal coals and 28 megatonnes per year of metallurgical coals. Actual production of thermal coals totalled 39 megatonnes or 90 percent of capacity; production of metallurgical coals totalled 23 megatonnes or 80 percent of capacity.

Except for the Cape Breton Island mines in Nova Scotia, virtually all Canadian coal production is from surface mines. Surface mining involves two different technologies for removal of overburden. At lignitic and subbituminous coal mines on the western prairies and in the mountain foothills, relatively inexpensive dragline stripping techniques are used. At bituminous coal mines in the mountain region more expensive shovel-truck units are employed.

Coal production increased continuously from 1969 through 1985 (Appendix Table A9-3) resulting from a growing domestic market for thermal coal and increases in exports of both metallurgical and thermal coals.

Coal production in 1987 is summarized by province and class in Table 9-5. More than 95 percent of 1987 production was extracted from mines using surface mining methods. Bituminous coals represented 53 percent of the total production on a volume basis; subbituminous and lignitic coals accounted for 30 and 16 percent, respectively. All subbituminous and lignitic coals, plus over 30 percent of the bituminous coals, were used for thermal purposes; this amounted to 38.5 megatonnes or 63 percent of production. Canada does not currently produce any anthracite.

Table 9-5

Coal Production by Province and Class in 1987

Province	Class	Megatonnes	Percentage of Total Production	Petajoules	Percentage of Total Production
British Columbia	Bituminous				
	Thermal	4.2	7	115.9	8
	Metallurgical	17.8	29	491.0	35
Alberta	Bituminous				
	Thermal	3.0	5	84.0	6
	Metallurgical	4.2	7	114.8	8
	Subbituminous	18.5	30	348.5	25
Saskatchewan	Lignite	10.0	16	144.3	10
New Brunswick	Bituminous				
	Thermal	0.5	1	14.7	1
Nova Scotia	Bituminous				
	Thermal	2.3	4	62.7	4
	Metallurgical	0.7	1	18.1	1
Canada	Bituminous				
	Thermal	10.0	16	277.3	20
	Metallurgical	22.6	37	623.9	45
	Subbituminous	18.5	30	348.5	25
	Lignite	10.0	16	144.3	10
	Total	61.2	100	1393.9	100
Canada	Thermal	38.6	63	770.1	55
	Metallurgical	22.6	37	623.9	45

Source: Statistics Canada, cat. no. 45-002 and cat. no. 57-003.

In 1987, Alberta produced 25.7 megatonnes of coal or 42 percent of total production in Canada. Coal production in British Columbia totalled 22 megatonnes and in Saskatchewan 10 megatonnes. Production in the Atlantic provinces was 3.5 megatonnes, 6 percent of total Canadian output.

In 1987, imports from the U.S. were 14.3 megatonnes, 95 percent of which were to Ontario. Over 75 percent of Ontario Hydro's requirements for bituminous coals for electricity generation were met by imports as well as over 98 percent of the industrial demand in Ontario for thermal coals. The remainder came from western Canada. In Quebec, 85 percent of the industrial demand for thermal coals was satisfied by imports with the remainder coming from Nova Scotia. Imported coals met over 95 percent of the metallurgical coal demand in Ontario and all of the demand in Quebec. In our projec-

tions we are assuming that Quebec will continue to be supplied mainly by U.S. coals and that in Ontario, because of high transportation costs, the use of western Canadian bituminous coals will maintain but not increase its share of the market. In sum, the import shares of thermal and metallurgical coal consumption in Ontario and Quebec are projected to remain constant.

A 1987 intergovernmental study on the use of western Canadian low sulphur coal in Ontario[1] recommended several initiatives which could reduce the cost of western coal to Ontario. It is not as yet known what actions will result from these recommendations.

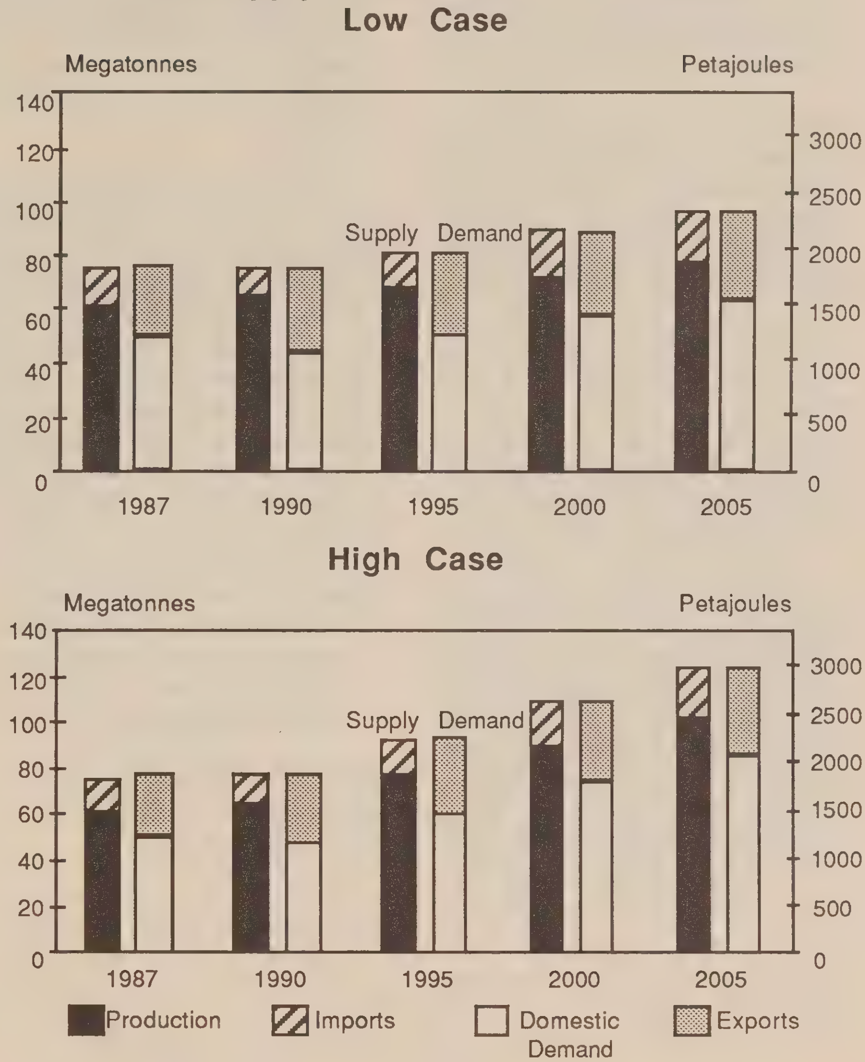
For New Brunswick, we are assuming that new coal-fired electricity generation plants (discussed in Chapter 5) will use imported coal.

By 2005, imports of thermal coals, mainly related to requirements for electricity generation in Ontario and in New Brunswick, are projected to be 11 megatonnes in both the low and high cases. We project that imports of metallurgical coal (which amounted to 5.8 megatonnes in 1987) will grow over the study period in response to demand from Ontario's steel industry, to 9 megatonnes in the low case and 11 megatonnes in the high case.

Our projection of future Canadian production levels is based on estimates of domestic demand, imports and exports. We expect coal production to increase modestly until the early 1990s in both the low and high cases (see Figure 9-3) and production to reach 77 megatonnes per year in 2005 in the low case. In the high case, we project more optimistic growth after 1995, with production reaching 102 megatonnes per year in 2005.

Figure 9-3

Coal Supply and Demand in Canada



Source: Appendix Table A9-4.

1. Intergovernmental Secretariat Report to the Action Committee on Western Canadian Low-Sulphur Coal to Ontario, 19 November, 1987.

9.6 Concluding Comments

Figure 9-3 summarizes our projections for both cases. (Detail is provided in Appendix Table A9-4.)

In both cases Canada continues to be a net coal exporter during the outlook period. Net exports of metallurgical coal remain large; for thermal coal Canada remains a modest net importer in most years.

There is a substantial difference in the coal outlook between the two cases:

- In the low case world economic growth is weak and prices of competing energy low. As a consequence both domestic demand and export growth are modest. Domestic demand for coal in the low case increases from 50 megatonnes in 1987 to 64 megatonnes in 2005. In this case total production grows from 61 megatonnes to 77 megatonnes over the same period and net coal exports, which were 12 megatonnes in 1987, increase to 20 megatonnes by 1990. However, as increased imports to Ontario and New Brunswick occur during the latter part of the review period, net exports return to current levels by 2005.
- The high case portrays a much more buoyant environment for Canadian coal. Both domestic and export demand grow considerably resulting in much more rapid growth in Canadian production than in the low case. Domestic demand increases in the high case from 50 megatonnes in 1987 to 86 megatonnes in 2005. Total production grows from 61 to 102 megatonnes over the same period. Net coal exports are projected to increase in this case from 12 to 18 megatonnes in 1990 and then to decline to 16 megatonnes in 2005.

There are, of course, major uncertainties associated with the future of coal in Canada:

- The extent to which Ontario Hydro will use coal for electricity production.
- The portion of the Ontario market that will be served by western Canadian coal.
- The extent to which coal will be able to displace natural gas used in the production of steam required for bitumen production.
- The ability of Canada to preserve its position in the export market.

Different projections on the future supply and demand for coal in Canada would, of course, result from alternate assumptions to those we have made. Our analysis suggests, however, that growth in Canadian coal production could be substantial in an environment of relatively high world economic growth and oil prices. For example, the share of coal in Canadian primary energy demand rises in our high case from less than 13 percent in 1987 to upwards of 15 percent in 2005.

Chapter 10

Sources and Uses of Energy

This chapter summarizes our projections of Canadian energy demand, supply and international trade, and contrasts Canadian energy flows to those observed in other countries. The analysis proceeds in terms of flows of primary energy, the total quantities of various energy forms used in the country.

Figure 10-1 shows energy flows in Canada and illustrates the relationship between the sources and uses of energy in 1986, and in 2005 for the low and high cases.

In moving from primary sources of energy to end use demand, we first identify all sources of primary energy, domestic primary energy production and imports. Subtracting exports from these energy sources leaves domestic demand for primary energy.

To arrive at end use demand from domestic demand for primary energy we subtract fuel use and losses associated with the production and distribution of energy. These include:

- fuel to produce oil and natural gas and move them from the field to final markets;
- fuel and losses in crude oil refining and in the reprocessing of natural gas to extract liquids;
- utilities' own use and losses in the transmission and distribution of electricity;
- conversion losses in electricity generation when coal, natural gas, oil and uranium are used in generating plants; for every unit of electricity produced, approximately three units of fuel input are required. We use a conversion factor of 10.5 petajoules per terawatt hour for electricity generated from fossil fuels and 12.1 petajoules per terawatt hour for electricity generated from uranium. (We convert hydro electricity at 3.6 petajoules per terawatt hour. See Chapter 5).

10.1 Canadian Energy Supply, Demand and Trade

Production of primary energy grows one percent per year from 1986 to 2005 in the low case and almost two percent in the high. The difference can be attributed mainly to our projection of a decline in crude oil production in the low case of 1.3 percent, while in the high case crude oil output increases by 1.4 percent per year. Oil's share of total primary energy production, which was 34 percent in 1986, declines to 22 percent in 2005 in the low case and 29 percent in the high (Figures 10-2 and 10-3).

Natural gas represented 28 percent of Canada's energy production in 1986. By the end of the study period, 37 percent of primary production is from natural gas in the low case and 32 percent in the high.

The share of coal production in primary energy is 14 and 15 percent in 2005 in the low and high cases respectively, a slight increase from its current level.

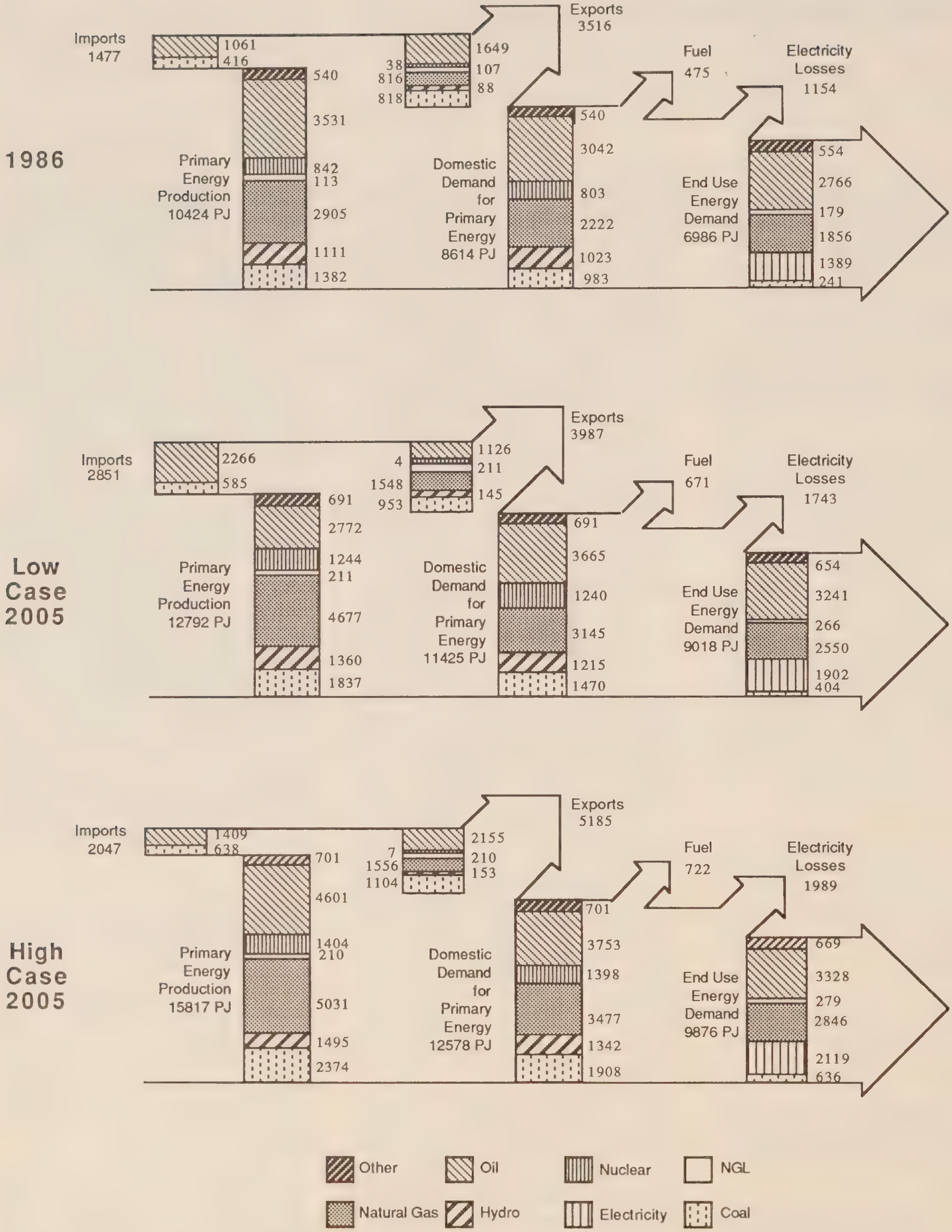
In 1986 hydro and nuclear production together accounted for about 20 percent of total primary production - a share which is maintained through 2005 in both cases.

Canada imports only coal and petroleum in volumes large enough to make an appreciable difference between gross and net exports. Coal imports rise in both cases from 416 petajoules in 1986 to 585 petajoules in 2005 in the low case and 638 petajoules in the high case, mainly to satisfy electricity generation requirements in Ontario. Petroleum imports also rise in both cases from about 1060 petajoules in 1986 to about 2265 petajoules in 2005 in the low case and 1410 petajoules in the high case.

In 1986 Canada imported 261 million cubic meters (9 Bcf) of natural gas from the U.S. to eastern Canada, equivalent to 0.4 percent of total Canadian production. While this trade flow may grow over the study period, we have not developed a projection for it. Therefore our supply and demand balances exclude gas imports.

In 1986, one-third of Canada's primary energy production was exported; thus exports are an important determinant of Canada's

Figure 10-1
Energy Flows



Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h and nuclear electricity converted to PJ using 12.1 PJ/TW.h

Source: Appendix Table A10-1

Figure 10-2
Primary Energy Production
Low Case

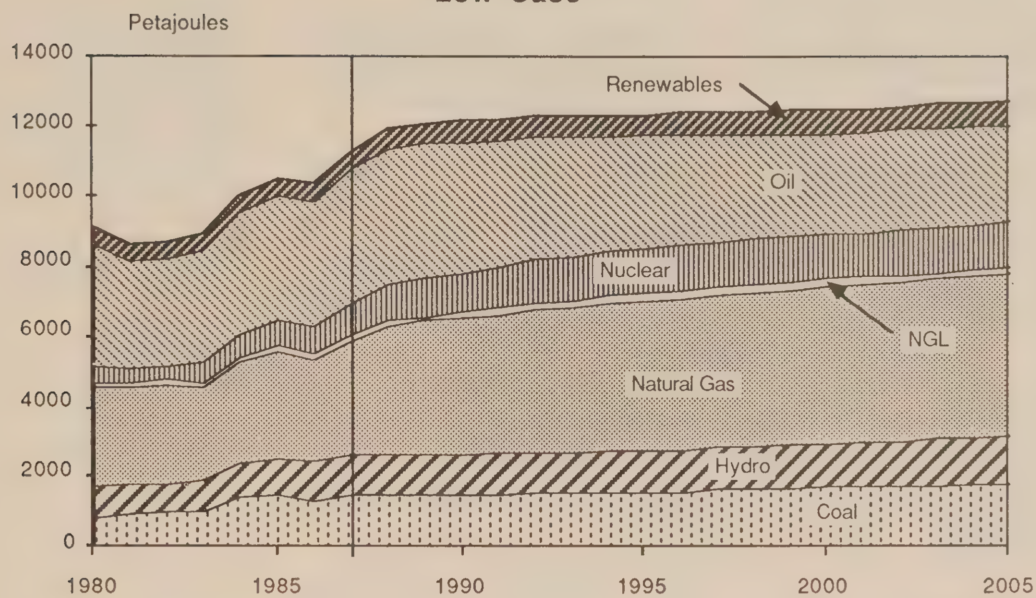
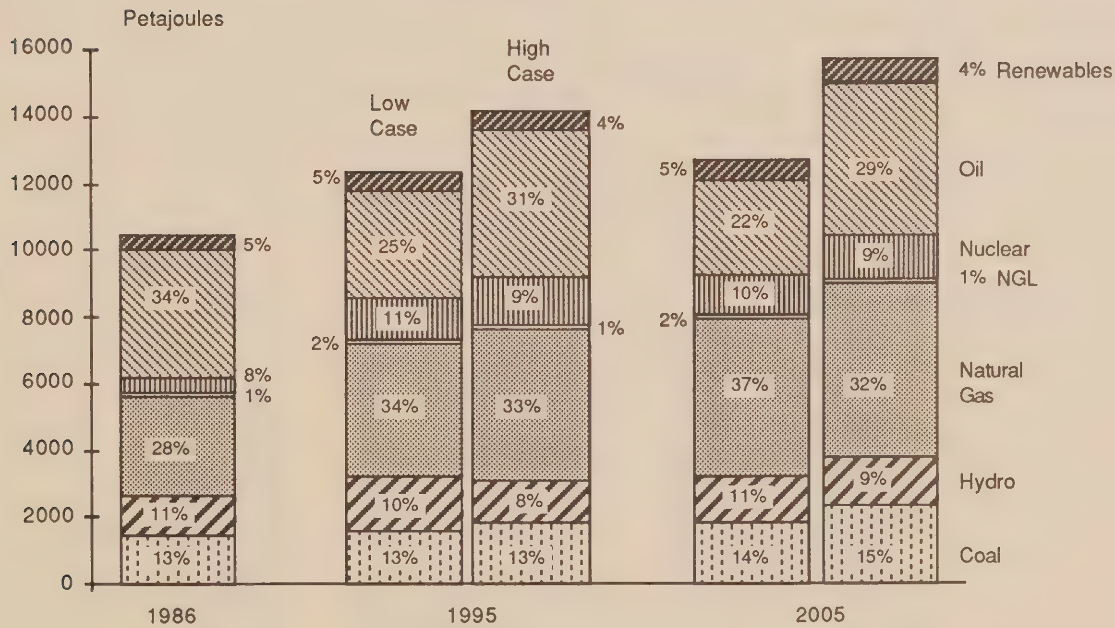


Figure 10-3
Primary Energy Production by Fuel
Canada



Sources: Renewables: Appendix Table A4-4
Oil: Appendix Table A7-16
NGL: Appendix Table A10-1
Natural Gas: Appendix Table A6-9
Hydro and Nuclear: Appendix Table A5-2
Coal: Appendix Table A9-4

Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h and nuclear electricity converted to PJ using 12.1 PJ/TW.h

energy output. In the low case there is an increase in total energy exports from a level of about 3500 petajoules in 1986 to 4000 petajoules in 2005; in the high case total exports increase to just over 5100 petajoules by 2005.

Differences in projected petroleum exports constitute most of the difference in total energy exports between the two cases; natural gas, electricity and coal exports hardly differ between the cases:

- Exports of crude oil and petroleum products evolve from about 1650 petajoules in 1986 to 1125 petajoules in 2005 in the low case and 2150 petajoules in the high.
- Natural gas exports rise from 794 petajoules in 1986 to about 1500 petajoules in the early 1990s in both cases, and remain at that level to 2005.
- Coal exports grow from 759 petajoules in 1986 to 900 to 1100 petajoules by 2005.
- Electricity exports increase from 140 petajoules in 1986 to 160 to 170 petajoules in 2005.

In 1986 (Table 10-1), net exports were 2000 petajoules, the result of exports of 3500 petajoules and imports of 1500 petajoules. In the low case, net exports decline to about 1100 petajoules in 2005, while in the high case they increase to about 3100 petajoules. This difference is accounted for mainly by differences in net petroleum exports between the two cases.

Figure 10-4 shows primary energy demand for domestic use for our low case, along with historical data. A comparison of the two cases is provided in Figure 10-5. The fuel shares of domestic demand for primary energy are similar in the high and low cases. Over the projection period, oil's share of demand declines (but not its absolute level), while those of nuclear, coal and natural gas increase. This reflects an increasing role for nuclear and coal generation of electricity, and increased use of natural gas.

Over the outlook period total domestic demand for primary energy grows at 1.5 percent annually in the low case and 2 percent in the high, growth rates which are similar to those of end use demand (1.4 and 1.8 percent respectively). The marginally higher growth rate of primary energy demand is due to an increase in the share of conversion losses in primary energy from 13 percent in 1986 to about 16 percent in 2005 in both cases. Conversion losses increase as a result of increased thermal generation of electricity.

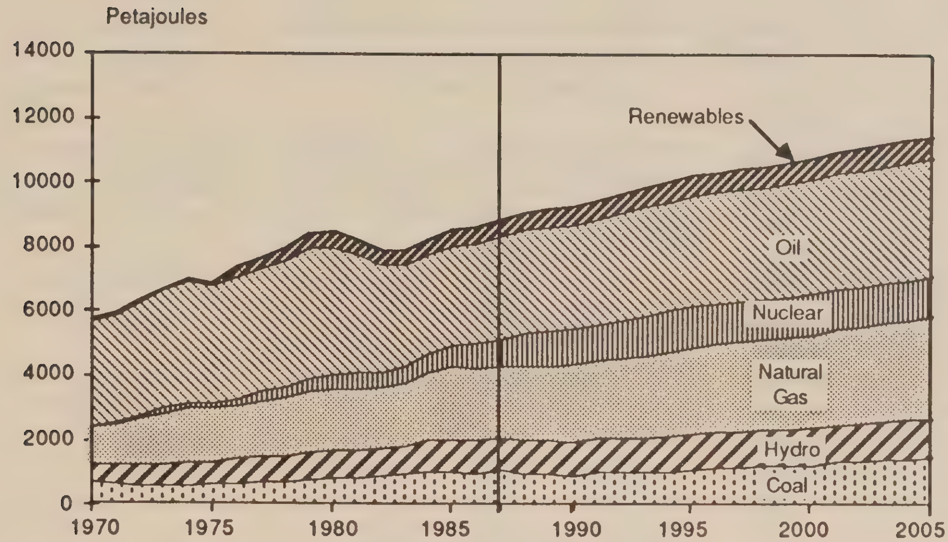
Table 10-1
Net Energy Exports (Imports)
(Petajoules)

			Low Case		High Case	
	1975	**1986**	**1995**	**2005**	**1995**	**2005**
Coal	(145)	360	445	320	445	415
Electricity	10	140	155	165	140	170
Natural Gas	1040	795	1500	1500	1500	1500
NGL	145	130	275	260	265	265
Crude oil & products	(110)	570	(645)	(1145)	815	740
Total	**940**	**2000**	**1730**	**1100**	**3165**	**3095**

Note: The numbers on this table have been rounded to the nearest unit of five.

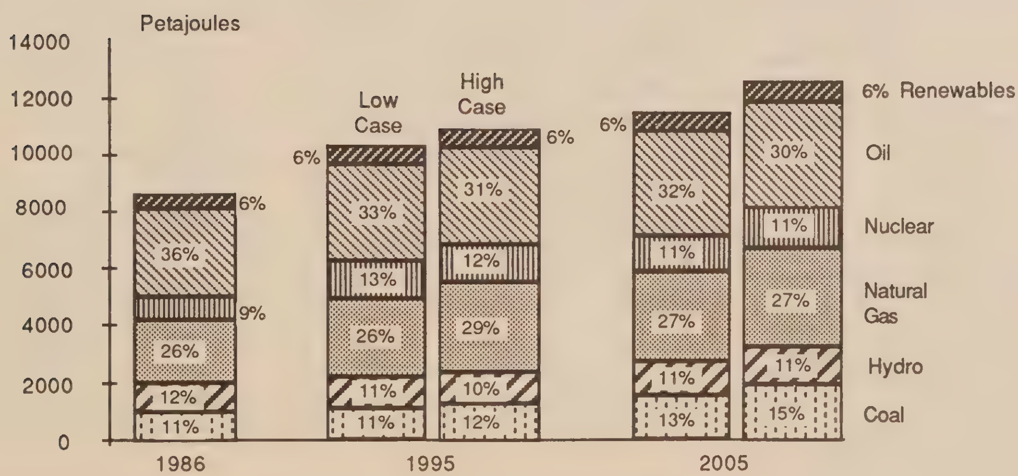
Source: Appendix Table A10-1.

Figure 10-4
Domestic Demand for Primary Energy
Low Case



Source: Appendix Table A10-1

Figure 10-5
Domestic Demand for Primary Energy by Fuel
Canada



Source: Appendix Table A10-1

10.2 International Perspective

Since the first oil price shock in 1973, countries and international organizations have been making international comparisons of energy use and energy intensity (energy use per capita or per unit of goods and services produced). These comparisons, such as those published by the International Energy Agency in its annual review, purport to be useful indicators of how well countries are doing in improving their energy efficiency relative to that of others. Implicit in their use is the assumption that those countries which are using more energy per capita or per unit of output should strive to reduce their requirements further.

However, there may be valid reasons why one country's energy use exceeds that of another, which are not apparent in an aggregate analysis of this kind. Even comparisons of sectoral energy use across countries require detailed analysis to provide useful information.

Any comparison of energy consumption should consider the climate of the consuming country, the distribution of the population (whether or not it is highly dispersed as in Canada, when compared to that of other countries), and the mix of industrial output between energy-intensive and other industries.

Canada's energy producing sector is itself highly energy-intensive. It has an important petrochemical industry, and has a relatively higher share of energy-intensive industrial output[1] in its GDP than do most other major Organization for Economic Co-operation and Development (OECD) countries. The output of many of these sectors is exported to other OECD countries, with the energy embodied in the exports. In other words, other OECD countries are indirectly importing energy from Canada, which they would have used themselves had they made these products domestically.

Table 10-2 compares 1986 primary energy demand and production for Canada and other member countries of the OECD. For conversion of hydroelectricity to petajoules from kilowatt hours we have shown both the energy output and fossil fuel equivalence methods (see Section 5.4.2). The fossil fuel equivalence method is that most commonly used by international agencies. We feel, however, that the energy output measure provides a more valid comparison of energy use between those countries with a large complement of indigenous hydroelectricity and those without. Those countries which use fossil fuel to generate electricity suffer a loss of approximately two-thirds of the energy content of the fossil fuels in their conversion to electricity. If these fossil fuels were used for other purposes - for example, natural gas in residential, commercial or industrial use, or heavy fuel oil or coal directly in industrial use - there would be only a minor conversion loss. However, electricity generated from hydraulic sources does not incur such a conversion loss. The water used to generate the electricity does not have an alternate use in the context of energy production. By using the energy output measure we do not penalize those countries which can produce electricity economically without suffering the fossil fuel conversion loss.

Using the energy output measure rather than fossil fuel equivalence does not alter Canada's ranking in Table 10-2 with respect to major industrial countries, although it reduces the estimate of our primary energy demand by about 20 percent, relative to the fossil fuel equivalence measure, due to the importance of hydroelectricity in Canada's energy balance. The estimates of demand for Norway and New Zealand are reduced by 20 to 30 percent when the energy output measure is adopted, again reflecting the contribution of hydroelectricity to those countries' energy balances.

In only four OECD countries did energy production exceed primary demand in 1986, that is, these countries were net exporters of energy: Canada; Australia, with its abundant coal and natural gas reserves; the United Kingdom, with North Sea oil and gas; and Norway which, besides its North Sea reserves, has large hydroelectric resources. This data does not take into account that several countries, including Canada, consume relatively large amounts of energy which is subsequently exported in goods.

Table 10-2 shows that Canada was the most energy-intensive of all major OECD countries in 1986. Whether expressed on a per capita basis or per unit of output, and whether energy output or fossil fuel equivalence is used, Canadian energy use is high relative to that of other major countries. It has been argued that converting output or gross domestic product measures to a common currency (in this case 1980 U.S. dollars) may impart bias to the analysis, as these measures are sensitive to the base year chosen. However, our analysis suggests that this does not

---

1. Mining, smelting and refining, pulp and paper, iron and steel, chemicals, cement and petroleum and coal products.

Table 10-2

COMPARISON of ENERGY USE and PRODUCTION in OECD COUNTRIES in 1986

	Population (Millions) [1]	Gross Domestic Product (1980 $US Bill.) [2]	Primary Demand [a] (PJ) [3]	Production [a] (PJ) [4]	Primary Demand: Energy Output[a] Per Capita (GJ) [5]	Primary Demand: Energy Output[a] Per GDP (MJ) [6]	Primary Demand: Fossil Fuel Equivalent[b] Per Capita (GJ) [7]	Primary Demand: Fossil Fuel Equivalent[b] Per GDP (MJ) [8]	Average Annual Change in Primary Energy Demand [b] Per Unit of GDP [c] 1973 - 1985 Percent [9]
Australia	16.0	176	3187	5691	200	18	205	19	-0.1
Austria	7.6	84	980	315	130	12	154	14	-1.2
Belgium	9.9	125	1851	552	188	15	189	15	-2.3
CANADA	25.7	312	7972	9833	311	26	380	31	-1.0
Denmark	5.1	77	823	255	161	11	161	11	-1.9
Finland	4.9	61	1176	450	239	19	254	20	n.a.
France	55.4	731	8033	3361	145	11	152	12	n.a.
Germany	61.1	888	11226	5299	184	13	186	13	-1.7
Greece	10.0	43	748	304	75	17	77	18	0.9
Iceland	0.2	4	42	15	175	11	274	17	n.a.
Ireland	3.6	21	409	113	115	19	117	20	-1.3
Italy	57.2	508	5734	972	100	11	105	12	-1.5
Japan	121.5	1312	15152	2575	125	12	129	12	-2.8
Luxembourg	0.4	5	132	3	357	25	365	25	-4.7
Netherlands	14.6	182	2694	2648	185	15	185	15	-1.8
New Zealand	3.3	25	459	389	140	18	180	23	1.5
Norway	4.2	71	760	3117	182	11	272	16	-1.6
Portugal	10.2	27	521	72	51	19	56	21	1.4
Spain	38.5	235	2993	1093	78	13	82	13	0.5
Sweden	8.4	137	1966	1107	235	14	277	17	-0.5
Switzerland	6.6	112	975	367	148	9	178	10	0.4
Turkey	50.9	78	1799	1013	35	23	37	24	-1.1
U.K.	56.8	602	8581	10254	151	14	152	14	-2.0
U.S.	241.6	3215	73678	64375	305	23	312	23	-2.0
Total	**813.3**	**9033**	**151890**	**114174**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**-1.8[d]**
Canada - percentage of total	3.2%	3.5%	5.2%	8.6%	n.a.	n.a.	n.a.	n.a.	n.a.
- rank	9 th	7 th	6 th	3 rd	2 nd	1 st	1 st	1 st	14 th

Notes: The numbers on this table have been rounded.
[a] Hydro electricity converted to PJ using 3.6 PJ per TW.h, and Nuclear electricity converted to PJ using 10.5 PJ per TW.h.
[b] Hydro and nuclear electricity converted to PJ using 10.5 PJ/TW.h.
[c] GDP measured in billions of 1980 U.S. dollars.
[d] Excludes Finland, France, and Iceland.
n.a.: not available

Sources: Columns (1) to (8): OECD, Energy Balances of OECD Countries 1985/1986; Paris, 1988.
Column (9): International Energy Agency, Energy Policies and Programmes of IEA Countries, 1987 Review; Paris, 1988, page 65.

significantly alter the rankings shown in columns 5 through 8 of the table.

That Canada uses more energy per capita or per unit of output than her major trading partners should not necessarily be viewed in a negative light, unless there were evidence that energy is being used inefficiently. While aggregate comparisons are useful indicators for general trends, they should not be used as the basis for conclusions regarding energy efficiency.

In order to provide a better basis for assessing Canada's relative position, we have identified some specific factors which have caused international energy use to vary substantially, both through time and across countries.

In some countries, such as Japan, part of the improvement in energy intensity since the mid-1970s can be attributed to massive industrial restructuring away from energy and particularly electric-intensive industries. In Canada, conversely, additional aluminum smelters are being constructed due to Canada's favourable costs for hydroelectricity.

A study of international energy use in the residential sector[1] concluded that, when adjustments are made to reflect heating degree days, to normalize for varying dwelling sizes (larger in North America than in Europe) and to measure useful energy consumption,[2] Canadian residential energy requirements per square metre are lower than those of most European countries. However, it is evident that even further gains may be achieved as indicated by the fact that Sweden had lower residential requirements, adjusted on the same basis.

Improvements of energy use in Canada's transportation sector since 1973 have been comparable to or better than those of other OECD countries. The ratio of transportation energy use to total GDP is much higher in Canada and the United States than in Europe or Japan, attributable partly to the much greater distances in Canada and the United States. However, improvements in this ratio over the period 1973 to 1985 were greatest for Canada and the United States, when compared to other industrial countries, while in Germany, Italy and the United Kingdom this ratio has actually increased over the period.[3] The improvement reflects shifts to smaller and more efficient vehicles in North America.

The last column of Table 10-2 shows the change in primary energy demand per unit of GDP for the period 1973 to 1985. Measured on this basis only seven of the 21 countries had a slower rate of energy intensity improvement than Canada. This particular calculation measures electricity production from hydro and nuclear sources on the basis of fossil fuel equivalence, which introduces a bias against those countries which have increased their share of hydroelectricity over this period.

If we were to consider total final consumption (equivalent to secondary energy demand) rather than primary energy demand, Canada's improvement averages 1.9 percent annually over 1973 to 1985, compared to an IEA average of 2.3 percent. Canada would rank eighth with Norway on this basis, an improvement (from fourteenth) over the measure shown in Table 10-2.

---

1. L. Schipper, A. Ketoff, and A. Kahane "Explaining Residential Energy Use by International Bottom-up Comparisons" in Annual Review of Energy, Volume 10, 1985.
2. Energy is adjusted to take account of efficiencies of different fuels.
3. Steve Rive, "An International Comparison of Energy Use", Ontario Ministry of Energy, July 1987.

Chapter 11

Conclusions

The world energy environment in 1988 is similar to that of 1986 in that there remain substantial excess supplies of energy in world and North American markets and prices remain relatively depressed. The outlook for world oil prices has not changed materially since we conducted the analysis for the October 1986 Report, nor have our views about the levels of sustainable high and low prices. Our world oil price tracks are very similar to those we used in 1986.

However, the results of our current analysis differ substantially from those of our 1986 report due to a number of changes we have made to the framework within which we carried out our analysis:

- the relationship of our estimates of demand in the high and low cases differs because of the broader view we have taken on the relationship between economic growth and oil prices,

- we have increased our estimates of the resource base for crude oil and natural gas in the Western Canada Sedimentary Basin and we take more explicit account of the uncertainty associated with estimates of the resource base than we have previously done,

- our analysis of natural gas markets has been much expanded; in this report we assess the long-term prospects for exports in a market environment and we explore in much greater detail the implications of a negotiated pricing environment for demand, supply and prices of Canadian natural gas,

- our demand estimates are influenced by the fact that a number of electrical utilities have announced programs of demand management,

- our projection of electricity supply is influenced by our changed estimates of the demand profile and it could be affected by more interprovincial trade in electricity, a prospect of which we have taken account in our alternative electricity supply case.

All of the results of our analysis critically depend on the underlying assumptions we have used. Different assumptions about economic growth, about oil prices, about the hydrocarbon resource base, about the prospects for U.S. gas demand and the process of price determination for natural gas, about technological change and about the response of energy demand to economic growth and price changes would produce different results from those reported here. Where possible we have tried to outline the nature of the change which would result from different assumptions.

Notwithstanding the inherent uncertainties associated with an exercise of this kind, our results suggest a number of plausible conclusions about Canada's energy future.

Domestic Demand

Our estimated growth of end use energy demand in Canada is considerably less than the rate of economic growth with which it is associated. This is due partly to the way in which we have specified the linkage between oil prices and economic growth in our underlying scenarios, but it is also related to our judgement that energy demand growth will be modest even if energy prices were to grow at relatively low rates.

We expect ongoing improvements in the energy efficiency of energy-using equipment; technological change is resulting in the use of lower quantities of process inputs - including energy - per unit of output. Furthermore, we believe that governments, firms and consumers will largely retain attitudes developed over the 1970s and 1980s regarding energy conservation in general, and that of oil in particular. This is, in part, conditioned by fear of a recurrence of the oil price shocks of the 1970s. It also reflects the fact that new capital goods are now much more energy efficient than models they are replacing.

Demand is powerfully affected by the industrial composition of economic growth as well as by the overall rate of growth. Our scenarios have relatively high growth rates in the output of goods-producing industries which are, by their nature, energy intensive. If

the share of service industries in GNP were to remain at its 1986 level over our projection period, we estimate that end use energy demand in Canada would be about 400 petajoules (or 4 percent) less in 2005 than projected in our high case.

The shares of different fuels in energy demand do not change dramatically from their present levels in either of our two cases. The shares of both natural gas and electricity increase slightly at the expense of oil products and of alternative energy forms:

- The scope for a further decline in the share of oil is limited. The transportation sector remains largely captive to oil products. In non-transportation uses oil's share is already small in regions of the country where both natural gas and electricity are available and, in the Atlantic region, the price of electricity is high relative to that of fuel oil under our pricing assumptions.

- In the low case, the share of natural gas increases notwithstanding the low level of our crude oil price track. This reflects our treatment of natural gas supply costs and prices in this case. Were we to assume no reduction of gas supply costs and no streaming of natural gas prices to reflect the commodity value of gas to different users, the natural gas market could be smaller by about 615 petajoules in 2005 in the low case.

- The share of alternative energy sources declines marginally in both cases. Given the current state of technology, pricing practices for conventional energy sources, and the fact that alternative sources are already being used extensively where they are most viable (notably in the pulp and paper industry), we do not see any increase in the overall share of these energy sources. Nonetheless alternative energy sources increase in absolute terms by about 100 petajoules (20 percent) over our study period.

- Our analysis suggests that growth in coal demand could be substantial in an environment of high economic growth and oil prices.

In sum, in our two cases the growth rates of energy demand are well below those of economic growth. We recognize, however, that with plausible alternative assumptions about major factors determining energy demand, growth of energy use could exceed our projections.

Energy Exports

Energy exports are a large component of total energy production in Canada and an important export industry. We expect this to continue over the study period.

We project electricity exports to remain in the range of 45 to 50 terawatt hours. The share of firm exports in the total is likely to increase substantially over the study period reflecting strong demand for firm power in a number of U.S. regions. Interruptible energy exports are lower in the high case than in the low, because interruptible energy is made available from surplus generation capability, which is lower under the higher demand conditions of the high case.

The potential U.S. market for firm power from Canada is very large and it is possible that firm exports could be considerably larger than portrayed in our two main cases. Our alternative electricity supply case reflects this possibility. In that case electricity exports reach a level of 70 terawatt hours by 2005.

We project that exports of natural gas will rise rapidly to a level of about 1.5 exajoules per year over the study period in both cases. This is a result of our underlying projections of growing Canadian demand but little overall growth in U.S. demand for natural gas, and comparative productive capacity and incremental supply costs in both countries over time. The fact that export levels are very similar in our two cases reflects our assumption that gas supply costs in both Canada and the U.S. adjust to the low oil price environment of the low case. If supply costs were not to adjust, natural gas exports would be considerably lower in this case.

In both cases natural gas exports could have been higher had we assumed higher growth in U.S. gas demand or a less optimistic view of U.S. supply. Conversely a less optimistic view of Canadian gas supply would have reduced our estimate of exports.

Canada remains a net exporter of crude oil throughout the projection period in the high case, but becomes a net importer by the early 1990s in the low as the supply of light crude oil declines. In both cases we are a net importer of light crude, net import levels being much higher in the low case.

Net exports of heavy crude oil decline in the low case, but increase substantially in the high. In contrast to light crude, exports of heavy crude oil, in the high case, are likely to be limited more by the absorptive capacity of export markets than by Canadian supply, of which there is a large potential under our high case oil price track.

With respect to natural gas liquids we expect that production will continue to exceed domestic demand by a substantial margin; potential exports over our study period could well exceed recent levels.

There are prospects for an increase in exports of coal, particularly in a high growth, high oil price environment, but it will be difficult for Canadian producers to preserve their position in a highly competitive world market. Imports are also likely to increase to serve a rising demand in eastern Canada so that net exports increase only modestly and only in the high case.

Supply

Our projections of oil and natural gas supply are both higher than in 1986 partly because of the higher estimates of the resource base of the Western Canada Sedimentary Basin which we have used in this report. These higher resource base estimates imply higher reserves additions per unit of drilling effort, so that our unit supply costs tend to be lower.

For natural gas our supply estimates also reflect our analysis of the impact of market-sensitive pricing on gas markets. After current surpluses are worked off and demand presses against supply, natural gas prices will rise, inducing increases in reserves additions and in productive capacity. Thus our analysis of gas markets shows the implications for supply, demand and prices of maintaining balance between supply and demand for natural gas over our study period.

This contrasts with the analysis of the October 1986 Report in which we did not analyze the implications of a continuing export demand beyond the period of existing licence authorizations. Nor did we analyze at that time the implications for supply, demand and price of excess demand towards the end of the projection period.

In this report we have derived a natural gas price profile which preserves balance in the market. In other words we have shown what would have to happen to gas prices to avoid a supply-demand crossover.

The fact that our natural gas supply results are similar in both high and low cases is attributable to the fact that we have used lower costs of finding and producing natural gas in the low case than in the high. In our view this is reasonable, because history shows that, where prices are low, costs of exploration, drilling and production tend to be lower than they are when energy prices are high.

Our results do not imply that we think the prospects for natural gas supply are independent of market conditions. Nor do we wish to give the impression that the size of the gas resource base in the Western Basin is well defined; it is not. Rather our results suggest that natural gas supply and prices critically depend on the costs of finding and producing natural gas, which themselves may be different depending upon the industry environment and the size, quality and location of the resource base.

Had we used the same estimate of the resource base as in the October 1986 Report the incremental supply cost (including user costs) of gas in 2005, given our current profile of reserves additions, would likely be about 30 percent higher, $6.00 per gigajoule instead of our current estimate in the high case of $4.70 per gigajoule, both in 1987 dollars.

Our results suggest that a continuing low oil price environment would be a very difficult one for the natural gas industry. Failing some accommodation, either in the form of lower costs of exploration and production or of continued streaming of gas prices to different classes of consumers or both, the size of the market for Canadian gas could decline considerably in this environment.

Our supply estimates for conventional oil from the Western Canada Sedimentary Basin are higher in this report than they were in 1986 primarily because of the higher estimate of the resource base which we used and a more rapid development of the resources. In the high case we remain bullish about the prospects for bitumen production, though we recognize that there is considerable uncertainty about market prospects.

Synthetic light crude oil production increases only slightly in the low case. In the high case there is potential for large increases but great uncertainty about which process will be used to produce it.

Synthetic light crude can be produced either from integrated oil sands mining and upgrading plants or from the upgrading of heavy crude oil (conventional heavy crude oil or bitumen produced by an in situ process). The extent to which synthetic light crude is produced from independently upgrading heavy crude oil depends critically upon whether the cost of the upgrading can be recovered by the differential between the bitumen price in export markets and the price of light crude oil. This relationship is very uncertain and difficult to assess. This in turn may mean that production of synthetic light crude from integrated mining is more

likely, as its economic viability does not depend upon price differentials between light and heavy crude oils.

As a consequence we have included more synthetic light production from integrated mining plants than from the separate processes of heavy crude oil production and subsequent upgrading. We recognize the uncertainties associated with this judgement, and that a plausible scenario could have been constructed in which production of synthetic light from heavy crude upgrading was greater than from integrated mining operations.

In the high case we are more optimistic about frontier oil production in this report than we were in 1986. We are projecting higher production levels in the Mackenzie-Beaufort area, and production from small oil pools off the East Coast which we had not included in our 1986 estimates.

Electricity supply planning has changed considerably in recent years. The impetus to this change is that, as demand for electricity grows, so does public opposition to the main power generation technologies on grounds of environmental impacts or concern about safety of nuclear plants. Therefore, utilities are increasingly looking to new sources of supply, more interprovincial trade (Ontario/Quebec, New Brunswick/Quebec) and increasing rationalization of neighbouring provincial systems (Alberta/B.C.), the use of private power producers to supplement the generation capacity of provincial utilities, and the use of incentives to encourage users of electricity to reduce demand. None the less, based on our current views of demand growth, achievable conservation, load management and supply diversification, there will have to be large additions of conventional capacity to meet future requirements in both cases. It would require very different approaches to electricity pricing and supply policy for this conclusion to change.

In this vein it is important to note that we have conducted our analysis of Canada's energy requirements, of exports and of the supply of energy in Canada on the assumption that the existing framework of institutional practices and public policies would continue over our study period.

As we have noted, our assessment is that, within this framework, growth in energy demand is likely to be modest compared to past growth rates. None the less there is increasing concern in Canada and abroad that present patterns of energy use may not be compatible with tolerable environmental quality. There is concern for example about the implications of the "greenhouse effect" for the future of the planet. This has led increasing numbers of analysts in Canada and abroad to question existing policies and practices. It is argued that institutional practices and public policies will have to be changed to foster energy conservation and the use of much greater quantities of renewable, more environmentally benign, sources of energy.

Our study was not intended to determine the content of such a new set of policies, much less to assess their implications. We wish simply to point out that the energy future for Canada portrayed in this report is by no means immutable. It represents our view of how that future might plausibly evolve allowing for two alternative paths of world economic and oil price growth. But underlying that analysis is the fundamental premise that our energy business is conducted in the future much as it has been in the past - a premise which is increasingly in question.

List of Appendix Tables

APPENDIX 1

APPENDIX 2

APPENDIX 3

There is no Appendix 3 - data related to Chapter 3 is in Appendix 4.

APPENDIX 4

APPENDIX 7

APPENDIX 8

APPENDIX 9

APPENDIX 10

APPENDIX 11

Appendix 1
Table A1-1
Abbreviations of Names, Terms and Units

Names

"Act"	The National Energy Board Act
"ANG"	Alberta Natural Gas Company Limited
"A & S"	Alberta and Southern Gas Company Limited
"(the) Board" **"NEB"**	(the) National Energy Board
"CANMET"	Canadian Centre for Mineral and Energy Technology
"COGLA"	Canadian Oil and Gas Lands Administration
"CPA"	Canadian Petroleum Association
"DOE"	Department of Energy (U.S.)
"El Paso"	El Paso Natural Gas Company
"ERCB"	Alberta Energy Resources Conservation Board
"FERC"	Federal Energy Regulatory Commission (U.S.)
"GSC"	Geological Survey of Canada
"IPL" or "Interprovincial"	Interprovincial Pipe Line Company, A Division of Interhome Energy Inc.
"LOOP"	Louisiana Offshore Oil Port
"NGPA"	Natural Gas Policy Act (U.S.)
"Northwest"	Northwest Pipeline Corporation
"OECD"	Organization for Economic Cooperation and Development
"OPEC"	Organization of Petroleum Exporting Countries
"Pan-Alberta"	Pan-Alberta Gas Limited
"PGT"	Pacific Gas Transmission Company
"PG & E"	Pacific Gas and Electric

"October 1986 Report"	Canadian Energy Supply and Demand 1985-2005 Summary and detailed reports, National Energy Board, October, 1986
"SoCal"	Southern California Gas Company
"TCPL" or "TransCanada"	TransCanada PipeLines Limited
"Trans Mountain"	Trans Mountain Pipe Line Company Ltd.
"U.S."	United States
"WGML"	Western Gas Marketing Limited
"Westcoast"	Westcoast Energy Inc.

Terms

BER	Beyond Economic Reach
CO_2	Carbon Dioxide
CPE	Centrally Planned Economies
CTMP	Chemi-Thermo-Mechanical Pulping
EOR	Enhanced Oil Recovery
GDP	Gross Domestic Product
GNE	Gross National Expenditure
GNP	Gross National Product
LPG	Liquefied Petroleum Gases
NGL	Natural Gas Liquids
NGV	Natural Gas for Vehicles
RDP	Real Domestic Product
SNG	Synthetic Natural Gas
TMP	Thermo-Mechanical Pulping
WTI	West Texas Intermediate

Units

Prefix	*Multiple*	*Symbol*
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

Btu	=	British thermal unit
Bcf	=	Billion cubic feet
Tcf	=	Trillion cubic feet

$C	=	Canadian dollars
$US	=	United States dollars

GJ	gigajoule	=	10^9Joules
TJ	terajoule	=	10^{12}J
PJ	petajoule	=	10^{15}J
EJ	exajoule	=	10^{18}J

kW	kilowatt	=	10^3Watts
kW.h	kilowatt hour	=	10^3W.h
MW	megawatt	=	10^3kW
MW.h	megawatt hour	=	10^3kW.h
GW	gigawatt	=	10^6kW
GW.h	gigawatt hour	=	10^6kW.h
TW	terawatt	=	10^9kW
TW.h	terawatt hour	=	10^9kW.h

Table A1-2
Conversion Factors

Metric	*Imperial Equivalent Units*
1 cubic metre of oil	
(15°C and 922 kg/m^3)	= 6.292 26 barrels (60°F and 22°API)
(15°C and 855 kg/m^3)	= 6.292 58 barrels (60°F and 34°API)
(15°C and 739 kg/m^3)	= 6.294 03 barrels (equilibrium pressure, 60°F and 60°API)
1 cubic metre of natural gas (101.325 kilopascals and 15°C)	= 35.301 01 cubic feet = (14.73 psia and 60°F)
1 cubic metre of ethane (equilibrium pressure and 15°C)	= 6.330 barrels of ethane (equilibrium pressure and 60°F) = 9.930 thousand cubic feet of ethane gas (14.73 psia and 60°F)
1 cubic metre of propane (equilibrium pressure and 15°C)	= 6.300 0 barrels of propane (equilibrium pressure and 60°F)
1 cubic metre of butanes (equilibrium pressure and 15°C)	= 6.296 8 barrels of butanes (equilibrium pressure and 60°F)
1 tonne	= 1.102 311 short tons
1 kilojoule	= 0.948 213 3 British thermal units (Btu)
1 gigajoule (GJ)	= approximately 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf
1 petajoule (PJ)	= approximately 0.95 billion cubic feet of natural gas, or 165 000 barrels of oil, or 0.28 terawatt hours of electricity

Gross Energy Content Factors

Natural Gas (at 15°C, 101.325 kPa and free of water vapour.)

B.C.	- domestic	39.10 MJ/m^3
	- Huntingdon	39.10 MJ/m^3
	- Kingsgate	37.65 MJ/m^3
	- Grassy Point	38.20 MJ/m^3
Alberta	- domestic	38.80 MJ/m^3
	- Cardston	37.65 MJ/m^3
	- Aden	36.06 MJ/m^3
East of Alberta		37.65 MJ/m^3
Ethane (liquid)		18.36 GJ/m^3
Propane (liquid)		25.53 GJ/m^3
Butanes (liquid)		28.62 GJ/m^3
Crude Oil	- Light and Medium	38.51 GJ/m^3
	- Heavy	40.90 GJ/m^3
	- Pentanes Plus	35.17 GJ/m^3
Coal	- Anthracite	27.70 GJ/tonne
	- Bituminous	27.60 GJ/tonne
	- Subbituminous	18.80 GJ/tonne
	- Lignite	14.40 GJ/tonne
	- Average domestic use	22.20 GJ/tonne
Petroleum Products	- Aviation Gasoline	33.52 GJ/m^3
	- Motor Gasoline	34.66GJ/m^3
	- Petrochemical Feedstocks	35.17 GJ/m^3
	- Naphtha Specialties	35.17 GJ/m^3
	- Aviation Turbo	35.93 GJ/m^3
	- Kerosene	37.68 GJ/m^3
	- Diesel	38.68 GJ/m^3
	- Light Fuel Oil	38.68 GJ/m^3
	- Lubes and Greases	39.16 GJ/m^3
	- Heavy Fuel Oil	41.73 GJ/m^3
	- Still Gas	41.73 GJ/m^3
	- Asphalt	44.46 GJ/m^3
	- Petroleum Coke	42.38 GJ/m^3
	- Other Products	39.82 GJ/m^3
Electricity		
Secondary		3.6 MJ/kW.h
Primary	- Hydro	3.6 MJ/kW.h
	- Nuclear	12.1 MJ/kW.h

Table A1-3
Definitions

Adjusted Productive Capacity *Capacité de production rajustée*	The estimated productive capacity at any point in time, carrying forward for future use any productive capacity resulting from an earlier excess of productive capacity over production.
Associated Gas *Gaz associé*	Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir.
Base Load Capacity *Capacité de production de la charge de base*	Electricity generating equipment which operates to supply the load over most hours of the year.
Basic Oxygen Furnace *Convertisseur basique*	A process used in steel making. In this process molten raw iron, with added lime, is subjected to jets of pure oxygen. The oxygen burns out the carbon to produce steel.
Beyond Economic Reach Reserves *Réserves hors de portée économique*	Established reserves, which because of size, location or composition are not considered economically viable at the present time.
Biomass *Biomasse*	Organic material such as wood, crop waste, municipal solid waste and mill waste, processed for energy production.
Bitumen *Bitume*	See 'Crude Bitumen'
Blowdown *Purge rapide*	The production of gas, either from the gas cap of an oil reservoir, normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation.
Capacity Available (Electricity) *Capacité disponible (électricité)*	The sum of the Installed Capacity in a system plus firm purchases.
Capacity (Electricity) *Capacité (électricité)*	The maximum amount of power which a machine, apparatus or appliance can generate, utilize or transfer, expressed in kilowatts or some multiple thereof.
Carbon Dioxide Flooding *Injection de dioxyde de carbone*	An enhanced recovery process in which carbon dioxide is injected into an oil reservoir to increase recovery.
Chemical Flooding *Injection de produits chimiques*	An enhanced recovery process in which water, with added chemicals, is injected into an oil reservoir to increase recovery.

Chemi-Thermo-Mechanical Pulping
Technique chimio-thermo mécanique de la production de pâtes

Same as Thermo-Mechanical Pulping but with chemicals being added to the chips to further refine the pulp by removing the lignin.

Coal Gasification
Gazéification du charbon

The production of a synthetic natural gas from coal.

Coal Liquefaction
Liquéfaction du charbon

The production of a synthetic crude oil or related liquid fuel from coal.

Co-generation
Coproduction

A facility which produces steam heat as well as electricity with a resultant overall improvement in energy conversion efficiency.

Condensate
Condensat

As used in this report, synonymous with pentanes plus.

Continuous Casting
Coulée en continu

A process that directly casts molten steel in a primary mill into smaller and thinner sections without the need for reheating steel ingots.

Conventional Areas
Régions classiques (ou traditionelles)

Generally, the Western Provinces, Southwestern Ontario, and the southern part of the Yukon and Northwest Territories.

Conventional Crude Oil
Pétrole brut classique

Crude oil recoverable through wells where production can be achieved without altering the natural viscous state of the oil.

Conventional Heavy Crude Oil
Pétrole brut lourd classique

Conventional crude oil having a high density (generally greater than 900 kilograms per cubic metre). Appendix 7-3 shows production from the crude streams included in the National Energy Board's conventional heavy crude oil category.

Conventional Light Crude Oil
Pétrole brut léger classique

Conventional crude oil having a low density (generally less than 900 kilograms per cubic metre). Appendix 7-3 shows production from the crude streams included in the National Energy Board's conventional light crude oil category.

Conventional Producing Areas
Régions productrices classiques

Same as 'Conventional Areas'

Crude Bitumen
Bitume brut

Very heavy crude oil or tar consisting of a naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and other minerals, and that in its natural viscous state is not recoverable at a commercial rate through a well.

Crude Oil and Equivalent Hydrocarbons
Pétrole brut et hydrocarbures équivalents

Sometimes referred to as 'Crude Oil and Equivalent' Includes light and heavy crude oil, pentanes plus, bitumen and synthetic crude oil.

Deferred Reserves
Réserves reportées

Established natural gas reserves which are not currently available to a market for a specific reason, usually their involvement in efficient recovery of oil or LPG.

Electric Arc Technology
Technique de l'arc électrique

Use of electrical arcs in a furnace to efficiently produce very high temperatures for applications such as metal melting and coating and industrial drying.

Electricity Production
Production d'électricité

The amount of electric energy expressed in kilowatt hours or multiples of kilowatt hours produced in a year. The determination of electric energy production takes into account various factors such as the type of service for which generating units were designed (e.g., peaking or base load) the availability of fuels, the cost of fuels, river water levels, and environmental constraints.

End Use Demand for Energy (or Secondary Energy Demand)
Demande d'énergie pour utilisation finale (ou demande d'énergie secondaire)

Energy used by final consumers for residential, commercial, industrial and transportation purposes, and hydrocarbons used for such non-energy purposes as petrochemical feedstock.

Energy Intensity
Intensité énergétique

In the industrial and commercial sectors and in transportation other than automobiles energy intensity is defined as the amount of energy per unit of production. In the residential sector it is energy use per household and for automobiles it is energy use per car. A measure of the efficiency with which energy is used in the economy as a whole is total end use energy per unit of GNP.

Enhanced Oil Recovery (or Enhanced Recovery)
Récupération assistée

See 'Recovery - Enhanced'

Established Reserves
Réserves établies

Those (oil and gas) reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgment portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.

Experimental Crude Oil
Pétrole brut expérimental

Crude oil produced from pilot projects designed to investigate new recovery techniques.

Feedstock
Charge d'alimentation

Raw material supplied to a refinery or petrochemical plant.

Firm Power
Puissance garantie

Electric power intended to be available at all times during the period covered by an agreement.

Flat Life
Cycle de vie fixe

That period of the producing life of a resource during which production is maintained at a constant rate.

Frontier Areas
Régions pionnières

Generally, the northern and offshore areas of Canada.

Fuel Efficiency (Burner Tip Efficiency)
Rendement du combustible (rendement à la pointe du brûleur)

The ratio of the useful output energy which results when a fuel is burned, to the theoretical input energy content of the fuel. Fuel efficiency for a heating fuel is less than 100 percent to the extent that heated air is used in combustion and to the extent that exhaust venting is necessary. In other applications fuel efficiencies are less than 100 percent partly because of waste heat generation.

Gas Cycling
Recyclage de gaz

The reinjection of part or all of the produced natural gas into the reservoir after removal of natural gas liquids.

Heavy Crude Oil
Pétrole brut lourd

A collective term used to refer to conventional heavy crude oil and crude bitumen. For the purposes of this report, heavy crude oil supply and demand numbers include heavy crude oil as well as any light fractions added to reduce viscosity to facilitate pipeline transportation but exclude any conventional heavy crude oil or bitumen upgraded to light crude oil.

Heavy Fuel Oil
Mazout lourd

In this report the term heavy fuel oil is used to include bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil).

High Case
Scénario élevé

See Chapter 2 Based on assumption of high economic growth and high world oil prices

Hog Fuel
Résidus de bois

Fuel consisting of pulverized bark, shavings, sawdust, low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.

Hybrid System
Système hybride

A dual fuel heating system using two alternative sources of energy.

Hydroelectric Generation
Production hydro-électrique

Electricity produced by an electric generat or driven by a hydraulic turbine.

Infill Drilling
Forage intercalaire

The process of drilling additional wells within the defined pool outline of a natural gas or oil pool.

Initial Established Reserves
Réserves établies initiales

Established reserves prior to the deduction of any production.

In Situ Recovery
Récupération en place

The process of recovering crude bitumen from oil sands other than by surface mining.

Interruptible Energy
Énergie interruptible

Electric power and/or energy made available under an agreement that permits curtailment or cessation of availability at the option of the supplier.

Light Crude Oil
Pétrole brut léger

A collective term used to refer to conventional light crude oil, upgraded heavy crude oil, synthetic crude oil and pentanes plus. For the purposes of this report, light crude oil supply and demand numbers exclude any light crude fractions added to heavy crude oil.

Light Fuel Oil
Mazout léger

In this report the term light fuel refers to furnace fuel oil (No. 2 fuel oil), kerosene and stove oil (No. 1 fuel oil). The major volume of light fuel oil used in Canada is furnace fuel oil.

Liquefied Petroleum Gases
Gaz de pétrole liquéfiés

As used in this report, the term refers to the hydrocarbons propane and butanes, or combinations thereof.

Load Factor
Facteur de charge

The ratio of the average load over a designated period of time to the maximum load occurring in that period, expressed in percent.

Low Case
Scénario bas

See Chapter 2
Based on assumption of low economic growth and low world oil prices

Marketable Natural Gas
Gaz naturel commercialisable

Natural gas which meets specifications for end use.

Middle Distillates
Distillats moyens

The range of refined petroleum products which includes kerosene, stove oil, diesel fuel, and light fuel oil.

Miscible Flooding
Injection de fluides miscibles

An enhanced recovery process in which a fluid, capable of mixing completely with the oil it contacts, is injected into an oil reservoir to increase recovery.

Natural Gas Liquids
Liquides de gaz naturel

The hydrocarbons, ethane, propane, butanes, and pentanes plus or a combination thereof.

Non-Associated Gas *Gaz non associé*	Natural gas not in contact with crude oil in the reservoir.
Non-Conventional Generation *Production non classique*	The generation of electricity by any means other than hydroelectric generation, thermal generation using nuclear fuel, coal, oil or natural gas, gas turbine generation using oil or natural gas, or internal combustion generation. Examples would be solar power and wind energy.
Oil Sands *Sables pétrolifères ou sables bitumineux*	Deposits of sand or sandstone, or other sedimentary rocks containing crude bitumen.
Peak Demand (Electricity) *Demande de pointe (électricité)*	The highest level of power demand by customers on a power system within a specified period, usually a year, (i.e., on a major utility, a minor utility or an individual industry generating its own electricity). The peak demand is measured in kilowatts or multiples of kilowatts.
Peaking Capacity *Capacité de pointe*	Electricity generating equipment which is available to meet peak demand.
Pentanes Plus *Pentanes plus*	A liquid by-product of natural gas production which is composed primarily of pentanes and heavier hydrocarbons.
Permeability *Perméabilité*	A measure of the capacity of a reservoir rock to transmit a fluid (liquid or gas).
Plasma Arc Technology *Technique de l'arc sous plasma*	Use of electrical arcs in a plasma furnace to efficiently produce very high temperatures for applications such as metal melting and coating, and industrial drying.
Primary Energy Demand *Demande d'énergie primaire*	Represents the total requirement for all uses of energy in Canada, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another (e.g. coal to electricity), and energy used by suppliers in providing energy to the market (e.g. pipeline fuel). (For the calculation of primary energy demand, see Appendix Table A10-1.) By definition: Primary energy demand = end use energy demand + energy supply industry use - electricity and steam demand + energy used to generate electricity and produce steam + other conversion losses

Primary Recovery
Récupération primaire

See 'Recovery - Primary'

Productive Capacity
Capacité de production

The estimated rate at which natural gas, crude oil or crude bitumen can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the existence of gathering, processing and transmission facilities, and potential losses due to mechanical breakdown.

Pulping Liquor (also known as waste liquor or black liquor)
Liqueur de pâte

A substance primarily made up of lignin, other wood constituents, and chemicals which are by-products of the manufacture of chemical pulp. It can be burned in a boiler to produce steam or electricity, through thermal generation.

Rate of Take
Taux d'extraction

The average daily rate of production of natural gas related to the volume of initial established reserves assigned to the reservoir or reservoirs from which the production is obtained. For example, 1:7300 means one unit of production a day for each 7 300 units of initial established reserves.

Raw Natural Gas
Gaz naturel brut

Unprocessed natural gas.

Recovery - Primary
Récupération primaire

The volume of crude oil recoverable from a reservoir through natural depletion processes only.

- Secondary
- secondaire

The incremental volume of crude oil recoverable from a reservoir through the utilization of a pressure maintenance scheme such as waterflooding or gas injection.

- Tertiary
- tertiaire

The incremental volume of crude oil recoverable from a reservoir other than through natural depletion and pressure maintenance processes.

- Enhanced
-assistée

The incremental volume of crude oil recoverable from a reservoir through a production process other than natural depletion; the production process used to achieve such incremental volume. Enhanced recovery includes both secondary and tertiary recovery.

Refinery Acquisition Cost
Coût d'achat à la raffinerie

The delivered price of crude oil to a refinery, including all transportation charges to that point.

Remaining Capacity (Electricity)
Capacité restante (électricité)

The difference between Capacity Available and the System Peak Demand. The remaining capacity includes the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements and unforeseen loads. On a national basis it is the difference between the aggregate net Capacity Available of the various systems in Canada and the sum of the System Peak Demands, without allowance for time diversity between the loads of the several systems.

Remaining Established Reserves
Réserves établies restantes

Initial established reserves less cumulative production.

Remaining Potential
Potentiel restant

That portion of the ultimate potential not yet discovered but which, on the basis of geological or other evidence, is inferred to exist and is expected to be developed by the time all exploratory and development activity has ceased. In the case of oil reservoirs to which established reserves have already been assigned, the remaining potential includes those additional quantities that are expected to be recoverable under enhanced recovery mechanisms not yet in place.

Reprocessing Shrinkage
Pertes en cours de retraitement

That quantity of natural gas removed from main gas transmission systems at straddle plants and coverted to NGL, expressed in either volume or energy units.

Reserves Additions
Additions aux réserves

Incremental changes to established reserves resulting from the discovery of new pools and reserves appreciation.

Reserves Appreciation
Valorisation des réserves

Incremental change in established reserves resulting from extensions to existing pools and/or revisions to previous reserves estimates.

Reserves Life Index
Indice de durée des réserves

Remaining reserves divided by annual production.

Retrofitting - A house:
Réfection - d'une résidence

Upgrading an existing house to reduce heat loss. Retrofitting includes measures such as adding insultation, caulking, weatherstripping and adding or improving storm windows and doors.

- A heating system:
- d'un système de chauffage

Replacing selected system components to increase efficiency while retaining most of the original system.

R-2000 homes *Maisons R-2000*	Type of new super efficient homes which are expected to meet the standard building code of the year 2000.
Secondary Recovery *Récupération secondaire*	See 'Recovery - Secondary'
Shut-in Capacity *Capacité inutilisée*	The unused productive capacity of an oil or gas pool or area.
Social Supply Cost *Coût social des approvisionnements*	The sum of capital and operating costs per unit of production, exclusive of royalties, taxes, subsidies, or incentive payments, discounted at the estimated social opportunity cost of capital in Canada.
Solar Energy - Active System *Énergie solaire - système actif*	Solar energy collection system which transfers heat captured from solar radiation through mechanical devices.
Solar Energy - Passive System *Énergie solaire - système passif*	Solar energy collection system which captures solar radiation directly for space heating, water heating or other similar purposes, without the use of mechanical devices.
Solution Gas *Gaz en solution*	Natural gas in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.
Solvent Flooding *Injection de solvant miscible*	See 'Miscible Flooding'
Straddle Plant *Usine de chevauchement*	A natural gas processing plant, located on a main gas transmission system, which extracts NGL from the gas stream.
Synthetic Crude Oil *Pétrole brut synthétique*	Crude oil resulting from the processing of crude bitumen.
Synthetic Natural Gas *Gaz naturel synthétique*	Natural gas produced from petroleum liquids, coal or wood.
Tertiary Recovery *Récupération tertiaire*	See 'Recovery - Tertiary'
Thermal Generation *Production thermique*	Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity in a generator. Normally, the fuel may be coal, oil, gas, or uranium (nuclear).
Thermal Processes *Procédés thermiques*	Enhanced oil recovery processes in which heat is added to the reservoir to increase recovery.

Thermo-Mechanical Pulping Process
Technique thermomécanique de la production de pâtes

A process used in the pulp and paper industry. Electrically produced mechanical energy is used to steam and refine wood chips into pulp. The steaming process softens the wood chips with the result that the pulp produced is of a higher quality than that obtained from other processes. Recovered steam may be used for space heating or for drying pulp fibres.

Transfer Capability
Capacité de transfert

The overall capacity of interprovincial or international power lines, together with the associated electrical system facilities, to transfer power and energy from one electrical system to another.

Upgrading
Valorisation

The processing of bitumen or heavy crude oil into a synthetic crude oil.

Ultimate Potential
Potentiel ultime

An estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of the area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves and future additions through extensions and revisions to existing pools and the discovery of new pools.

Waterflooding
Injection d'eau

An enhanced recovery process in which water is injected into an oil reservoir to increase recovery.

Wellhead
Tête du puits

Specifically, the equipment at the top of a well for maintaining control of the well. More generally, it is used to specify a reference or delivery point on the production system.

World Oil Price
Prix mondial du pétrole

As used in this report, the term refers to the official selling price of West Texas Intermediate crude oil at Chicago.

Wood Gasification
Gazéification du bois

The production of a synthetic natural gas from wood.

Wood Liquefaction
Liquéfaction du bois

The production of liquids (e.g. methanol) from wood.

Wood Waste
Résidus de bois

Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.

Wood Wastes
Déchets de bois

Refers to wood waste and pulping liquor.

Appendix 2

Table A2-1
World Oil Prices

	1970	1971	1972	1973	1974	1975	1976	1977
($U.S. 1987 / Barrel)	4.87	6.00	6.26	8.22	27.37	27.39	28.65	29.17
($C 1987 / Cubic Metre)	40.09	48.82	49.63	64.72	206.67	212.27	210.61	226.59

	1978	1979	1980	1981	1982	1983	1984	1985
($U.S. 1987 / Barrel)	27.82	34.79	52.94	45.80	39.17	35.13	32.78	30.08
($C 1987 / Cubic Metre)	228.37	292.19	439.72	380.28	320.30	281.59	274.38	264.99

($U.S. 1987 / Barrel)	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Low Case	15.95	19.56	15.00	15.00	15.00	15.20	15.40	16.00	18.00	20.00
High Case	15.95	19.56	20.00	21.00	22.00	23.00	24.00	27.00	30.00	30.00
($C 1987 / Cubic Metre)										
Low Case	141.18	163.22	122.63	121.19	121.72	123.56	125.06	129.78	140.83	156.09
High Case	141.18	163.22	161.21	168.64	179.56	189.55	199.08	225.14	248.35	247.66

Note: West Texas Intermediate at Chicago.

Table A2-2
Real Gross Domestic Product Growth Rates - Canada and Regions

Average Annual Growth Rates	1986-1990	1990-1995	1995-2000	2000-2005
Atlantic Provinces				
Low Case	2.1	1.9	1.7	1.6
High Case	2.7	3.0	2.5	2.2
Newfoundland				
Low Case	1.1	1.3	1.7	1.9
High Case	3.8	4.9	3.3	2.0
Prince Edward Island				
Low Case	2.0	2.1	1.8	1.4
High Case	1.9	2.4	2.2	2.1
Nova Scotia				
Low Case	2.1	2.0	1.8	1.4
High Case	2.3	2.4	2.3	2.2
New Brunswick				
Low Case	2.7	2.2	1.5	1.8
High Case	2.7	2.3	2.0	2.5
Central Canada				
Low Case	2.8	2.8	2.0	1.8
High Case	3.4	3.4	2.8	2.6
Quebec				
Low Case	3.2	2.5	1.8	1.5
High Case	3.5	2.9	2.5	2.3
Ontario				
Low Case	2.6	3.0	2.1	2.0
High Case	3.3	3.6	3.0	2.8
Prairies				
Low Case	0.6	1.8	2.1	2.2
High Case	2.5	3.1	2.8	2.1
Manitoba				
Low Case	2.1	2.0	1.7	2.3
High Case	2.4	2.6	2.3	2.6
Saskatchewan				
Low Case	1.4	2.3	2.2	2.2
High Case	2.4	3.0	3.1	2.6
Alberta				
Low Case	- 0.3	1.5	2.2	2.3
High Case	2.5	3.4	2.9	1.8
B.C. and Territories				
Low Case	2.0	2.2	2.0	2.2
High Case	2.2	2.6	2.5	2.8
Canada				
Low Case	2.3	2.5	2.0	1.9
High Case	3.0	3.2	2.8	2.5

Note: The numbers on this table have been rounded.

Appendix 4

Table A4-1
Real Average Retail Prices by Region and Sector

($1987/Output Gigajoule)

Atlantic

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	12.78	12.25	10.60	10.55	10.57	10.65	10.71	10.91	11.39	11.99
Electricity	16.49	15.60	15.53	15.53	15.53	15.53	15.53	15.53	15.53	15.53
Natural Gas	14.37	14.33	13.15	13.45	13.54	13.50	13.66	14.53	15.87	17.70
Commercial										
Light Fuel Oil	10.06	9.64	8.11	8.06	8.08	8.15	8.21	8.40	8.84	9.40
Heavy Fuel Oil	6.95	6.61	4.85	4.80	4.82	4.90	4.96	5.15	5.61	6.18
Electricity	22.88	22.35	22.28	22.28	22.28	22.28	22.28	22.28	22.28	22.28
Natural Gas	21.57	22.30	20.45	20.59	20.65	20.63	20.76	21.46	22.56	24.08
Industrial										
Heavy Fuel Oil	4.75	4.52	3.32	3.28	3.30	3.35	3.39	3.52	3.83	4.23
Electricity	14.57	14.19	14.03	14.03	14.03	14.03	14.03	14.03	14.03	14.03
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	12.78	12.25	12.18	12.48	12.91	13.30	13.67	14.67	15.56	15.53
Electricity	16.49	15.60	15.39	15.39	15.39	15.39	15.39	15.39	15.39	15.39
Natural Gas	14.37	14.33	13.47	13.22	13.08	13.31	13.78	14.56	15.89	17.45
Commercial										
Light Fuel Oil	10.06	9.64	9.58	9.86	10.25	10.61	10.96	11.89	12.72	12.69
Heavy Fuel Oil	6.95	6.61	6.37	6.66	7.07	7.44	7.79	8.76	9.61	9.58
Electricity	22.88	22.35	22.07	22.07	22.07	22.07	22.07	22.07	22.07	22.07
Natural Gas	21.57	22.30	20.61	20.37	20.24	20.57	21.01	21.76	23.03	24.52
Industrial										
Heavy Fuel Oil	4.75	4.52	4.36	4.55	4.83	5.09	5.33	5.99	6.57	6.55
Electricity	14.57	14.19	13.90	13.90	13.90	13.90	13.90	13.90	13.90	13.90
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas = 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas = 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas = 85 percent.
Electricity is assumed to be 100 percent efficient in all sectors.

Table A4-1 (Continued)
Real Average Retail Prices by Region and Sector

($1987/Output Gigajoule)

Quebec

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	10.94	11.46	9.71	9.65	9.68	9.76	9.83	10.04	10.55	11.18
Electricity	12.36	12.38	12.52	12.46	12.46	12.46	12.46	12.46	12.46	12.46
Natural Gas	10.46	10.26	9.20	9.41	9.42	9.31	9.40	10.35	11.82	13.81
Commercial										
Light Fuel Oil	8.61	9.02	7.39	7.34	7.36	7.44	7.50	7.70	8.17	8.76
Heavy Fuel Oil	6.10	7.09	4.85	4.80	4.82	4.90	4.96	5.15	5.61	6.18
Electricity	14.79	14.92	15.20	14.88	14.88	14.88	14.88	14.88	14.88	14.88
Natural Gas	8.74	8.52	7.60	7.67	7.69	7.62	7.71	8.46	9.67	11.32
Industrial										
Heavy Fuel Oil	4.18	4.85	3.32	3.28	3.30	3.35	3.39	3.52	3.83	4.23
Electricity	8.55	8.64	8.78	8.66	8.66	8.66	8.66	8.66	8.66	8.66
Natural Gas	5.62	5.29	3.84	3.83	3.83	3.85	3.88	4.01	4.32	4.74

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	10.94	11.46	11.39	11.71	12.16	12.58	12.97	14.04	14.98	14.95
Electricity	12.36	12.38	12.40	12.42	12.42	12.42	12.42	12.42	12.42	12.42
Natural Gas	10.46	10.26	9.54	9.16	8.94	9.20	9.70	10.56	12.01	13.70
Commercial										
Light Fuel Oil	8.61	9.02	8.95	9.25	9.67	10.06	10.42	11.41	12.29	12.26
Heavy Fuel Oil	6.10	7.09	6.37	6.66	7.07	7.44	7.79	8.76	9.61	9.58
Electricity	14.79	14.92	15.06	14.83	14.83	14.83	14.83	14.83	14.83	14.83
Natural Gas	8.74	8.52	7.76	7.44	7.25	7.61	8.09	8.90	10.29	11.91
Industrial										
Heavy Fuel Oil	4.18	4.85	4.36	4.55	4.83	5.09	5.33	5.99	6.57	6.55
Electricity	8.55	8.64	8.70	8.63	8.63	8.63	8.63	8.63	8.63	8.63
Natural Gas	5.62	5.29	3.85	4.17	4.57	4.84	5.20	5.79	6.81	8.00

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas = 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas = 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas = 85 percent.
Electricity is assumed to be 100 percent efficient in all sectors.

($1987/Output Gigajoule)

Ontario

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	12.12	12.68	11.07	11.02	11.04	11.12	11.18	11.38	11.84	12.46
Electricity	13.45	13.53	13.79	13.79	13.79	13.79	13.79	13.79	13.79	13.79
Natural Gas	9.31	8.80	8.21	8.51	8.60	8.56	8.72	9.59	10.93	12.76
Commercial										
Light Fuel Oil	9.54	9.98	8.48	8.44	8.46	8.53	8.59	8.77	9.20	9.77
Heavy Fuel Oil	5.61	6.25	4.78	4.73	4.75	4.83	4.89	5.08	5.54	6.15
Electricity	15.72	15.91	16.38	16.38	16.38	16.38	16.38	16.38	16.38	16.38
Natural Gas	7.39	6.85	6.39	6.52	6.58	6.57	6.70	7.39	8.50	10.01
Industrial										
Heavy Fuel Oil	3.84	4.28	3.27	3.23	3.25	3.30	3.34	3.48	3.79	4.20
Electricity	8.81	8.90	9.22	9.22	9.22	9.22	9.22	9.22	9.22	9.22
Natural Gas	4.97	4.08	3.21	3.23	3.25	3.30	3.34	3.48	3.79	4.20

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	12.12	12.68	12.61	12.92	13.35	13.75	14.13	15.18	16.12	16.11
Electricity	13.45	13.53	13.66	13.66	13.66	13.66	13.66	13.66	13.66	13.66
Natural Gas	9.31	8.80	8.54	8.29	8.14	8.38	8.84	9.62	10.96	12.51
Commercial										
Light Fuel Oil	9.54	9.98	9.92	10.20	10.60	10.97	11.33	12.30	13.18	13.16
Heavy Fuel Oil	5.61	6.25	6.30	6.59	7.02	7.41	7.79	8.82	9.75	9.73
Electricity	15.72	15.91	16.23	16.23	16.23	16.23	16.23	16.23	16.23	16.23
Natural Gas	7.39	6.85	6.55	6.31	6.17	6.51	6.95	7.70	8.97	10.46
Industrial										
Heavy Fuel Oil	3.84	4.28	4.31	4.51	4.80	5.07	5.33	6.03	6.67	6.66
Electricity	8.81	8.90	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14
Natural Gas	4.97	4.08	3.23	3.57	3.99	4.26	4.62	5.21	6.24	7.42

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas = 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas = 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas = 85 percent.
Electricity is assumed to be 100 percent efficient in all sectors.

Table A4-1 (Continued)
Real Average Retail Prices by Region and Sector

($1987/Output Gigajoule)

Manitoba

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	12.97	12.75	11.14	11.09	11.11	11.19	11.25	11.45	11.91	12.53
Electricity	9.47	10.11	10.28	10.21	10.21	10.21	10.21	10.21	10.21	10.21
Natural Gas	7.74	7.70	6.53	6.85	6.94	6.91	7.07	7.99	9.42	11.36
Commercial										
Light Fuel Oil	9.74	9.63	8.05	8.00	8.02	8.09	8.16	8.35	8.80	9.41
Heavy Fuel Oil	7.95	7.86	5.14	5.09	5.11	5.20	5.26	5.48	5.98	6.66
Electricity	15.07	14.84	15.87	15.75	15.75	15.75	15.75	15.75	15.75	15.75
Natural Gas	6.42	6.11	5.31	5.45	5.52	5.51	5.64	6.38	7.55	9.16
Industrial										
Heavy Fuel Oil	4.85	4.84	3.17	3.13	3.15	3.20	3.24	3.37	3.68	4.10
Electricity	8.31	8.19	8.77	8.71	8.71	8.71	8.71	8.71	8:71	8.71
Natural Gas	4.16	3.71	2.37	2.39	2.41	2.46	2.50	2.63	2.95	3.36

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	12.97	12.75	12.68	12.99	13.42	13.82	14.20	15.25	16.19	16.18
Electricity	9.47	10.11	10.19	10.18	10.18	10.18	10.18	10.18	10.18	10.18
Natural Gas	7.74	7.70	6.89	6.62	6.46	6.72	7.21	8.04	9.45	11.10
Commercial										
Light Fuel Oil	9.74	9.63	9.56	9.86	10.28	10.68	11.05	12.08	13.00	12.99
Heavy Fuel Oil	7.95	7.86	6.83	7.16	7.63	8.07	8.49	9.63	10.66	10.64
Electricity	15.07	14.84	15.72	15.70	15.70	15.70	15.70	15.70	15.70	15.70
Natural Gas	6.42	6.11	5.49	5.24	5.09	5.44	5.91	6.71	8.06	9.63
Industrial										
Heavy Fuel Oil	4.85	4.84	4.21	4.41	4.70	4.97	5.23	5.93	6.56	6.55
Electricity	8.31	8.19	8.69	8.68	8.68	8.68	8.68	8.68	8.68	8.68
Natural Gas	4.16	3.71	2.39	2.73	3.15	3.42	3.78	4.38	5.40	6.59

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas = 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas = 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas = 85 percent.
Electricity is assumed to be 100 percent efficient in all sectors.

Table A4-1 (Continued)
Real Average Retail Prices by Region and Sector

Saskatchewan

($1987/Output Gigajoule)

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	11.29	11.87	10.26	10.21	10.24	10.31	10.37	10.57	11.03	11.65
Electricity	15.22	15.58	16.09	16.09	16.09	16.09	16.09	16.09	16.09	16.09
Natural Gas	6.21	5.82	5.41	5.65	5.78	5.84	6.04	6.84	8.13	9.86
Commercial										
Light Fuel Oil	8.87	9.15	7.65	7.61	7.63	7.70	7.76	7.94	8.37	8.95
Heavy Fuel Oil	7.24	7.47	4.87	4.82	4.84	4.92	4.99	5.19	5.68	6.33
Electricity	24.04	24.70	25.72	25.72	25.72	25.72	25.72	25.72	25.72	25.72
Natural Gas	5.12	4.67	4.30	4.53	4.65	4.72	4.90	5.54	6.59	8.02
Industrial										
Heavy Fuel Oil	4.78	4.77	3.11	3.07	3.09	3.14	3.18	3.32	3.63	4.04
Electricity	14.34	14.73	15.35	15.35	15.35	15.35	15.35	15.35	15.35	15.35
Natural Gas	3.74	3.08	2.80	2.96	3.06	3.11	3.18	3.32	3.63	4.04

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	11.29	11.87	11.81	12.11	12.54	12.94	13.33	14.37	15.32	15.30
Electricity	15.22	15.58	15.94	15.94	15.94	15.94	15.94	15.94	15.94	15.94
Natural Gas	6.21	5.82	5.55	5.69	5.92	6.31	6.85	7.66	9.07	10.73
Commercial										
Light Fuel Oil	8.87	9.15	9.09	9.37	9.77	10.14	10.50	11.47	12.35	12.33
Heavy Fuel Oil	7.24	7.47	6.50	6.81	7.27	7.69	8.09	9.20	10.19	10.17
Electricity	24.04	24.70	25.48	25.48	25.48	25.48	25.48	25.48	25.48	25.48
Natural Gas	5.12	4.67	4.44	4.57	4.79	5.17	5.68	6.46	7.81	9.39
Industrial										
Heavy Fuel Oil	4.78	4.77	4.15	4.35	4.64	4.91	5.17	5.87	6.51	6.50
Electricity	14.34	14.73	15.20	15.20	15.20	15.20	15.20	15.20	15.20	15.20
Natural Gas	3.74	3.08	2.92	2.99	3.16	3.46	3.88	4.50	5.58	6.84

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas = 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas = 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas = 85 percent.
Electricity is assumed to be 100 percent efficient in all sectors.

Table A4-1 (Continued)
Real Average Retail Prices by Region and Sector

($1987/Output Gigajoule)

Alberta

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	10.48	11.02	9.41	9.36	9.38	9.46	9.52	9.72	10.18	10.80
Electricity	13.18	12.68	12.93	12.93	12.93	12.93	12.93	12.93	12.93	12.93
Natural Gas	5.65	5.38	5.30	5.61	5.73	5.83	5.93	6.44	7.81	10.32
Commercial										
Light Fuel Oil	8.51	8.77	7.28	7.23	7.25	7.33	7.38	7.57	8.00	8.57
Heavy Fuel Oil	5.84	5.83	3.69	3.65	3.67	3.73	3.79	3.95	4.32	4.82
Electricity	17.61	16.88	16.46	16.46	16.46	16.46	16.46	16.46	16.46	16.46
Natural Gas	4.27	3.89	3.93	4.23	4.34	4.43	4.53	5.02	6.21	8.27
Industrial										
Heavy Fuel Oil	4.84	4.83	3.06	3.02	3.04	3.09	3.13	3.27	3.58	3.99
Electricity	10.93	10.47	10.49	10.49	10.49	10.49	10.49	10.49	10.49	10.49
Natural Gas	2.50	2.43	2.24	2.47	2.56	2.64	2.71	3.11	3.58	3.99

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	10.48	11.02	10.96	11.26	11.69	12.09	12.47	13.52	14.47	14.45
Electricity	13.18	12.68	12.81	12.81	12.81	12.81	12.81	12.81	12.81	12.81
Natural Gas	5.65	5.38	5.44	5.68	5.89	6.30	6.77	7.55	8.88	10.44
Commercial										
Light Fuel Oil	8.51	8.77	8.72	9.00	9.40	9.77	10.12	11.10	11.97	11.96
Heavy Fuel Oil	5.84	5.83	4.95	5.20	5.55	5.87	6.18	7.04	7.80	7.79
Electricity	17.61	16.88	16.31	16.31	16.31	16.31	16.31	16.31	16.31	16.31
Natural Gas	4.27	3.89	4.07	4.29	4.50	4.89	5.33	6.08	7.36	8.84
Industrial										
Heavy Fuel Oil	4.84	4.83	4.10	4.30	4.59	4.86	5.12	5.82	6.46	6.44
Electricity	10.93	10.47	10.39	10.39	10.39	10.39	10.39	10.39	10.39	10.39
Natural Gas	2.50	2.43	2.34	2.52	2.69	3.00	3.36	3.95	4.97	6.16

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas = 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas = 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas = 85 percent.
Electricity is assumed to be 100 percent efficient in all sectors.

Table A4-1 (Continued)
Real Average Retail Prices by Region and Sector

($1987/Output Gigajoule)

British Columbia and Territories

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	11.99	12.00	10.39	10.34	10.36	10.43	10.50	10.69	11.16	11.78
Electricity	12.96	12.42	12.69	12.69	12.69	12.69	12.69	12.69	12.69	12.69
Natural Gas	7.65	7.33	7.35	7.55	7.51	7.34	7.36	8.29	10.01	12.26
Commercial										
Light Fuel Oil	9.44	9.44	7.86	7.81	7.83	7.90	7.97	8.16	8.62	9.22
Heavy Fuel Oil	7.77	6.99	4.66	4.61	4.63	4.71	4.77	4.96	5.42	6.03
Electricity	17.19	16.78	16.17	16.17	16.17	16.17	16.17	16.17	16.17	16.17
Natural Gas	6.87	6.27	6.24	6.46	6.45	6.33	6.37	7.22	8.78	10.85
Industrial										
Heavy Fuel Oil	5.31	4.78	3.19	3.15	3.17	3.22	3.26	3.39	3.71	4.12
Electricity	9.47	9.24	8.91	8.91	8.91	8.91	8.91	8.91	8.91	8.91
Natural Gas	3.93	2.53	2.30	2.40	2.53	2.70	2.87	3.05	3.33	3.71

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Light Fuel Oil	11.99	12.00	11.93	12.23	12.67	13.07	13.45	14.50	15.44	15.42
Electricity	12.96	12.42	12.57	12.57	12.57	12.57	12.57	12.57	12.57	12.57
Natural Gas	7.65	7.33	7.26	7.08	6.97	6.90	7.36	8.15	9.48	11.03
Commercial										
Light Fuel Oil	9.44	9.44	9.38	9.67	10.10	10.49	10.87	11.90	12.83	12.81
Heavy Fuel Oil	7.77	6.99	6.18	6.47	6.90	7.29	7.67	8.70	9.63	9.61
Electricity	17.19	16.78	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02
Natural Gas	6.87	6.27	6.16	5.99	5.88	6.04	6.51	7.30	8.66	10.23
Industrial										
Heavy Fuel Oil	5.31	4.78	4.23	4.43	4.72	4.99	5.25	5.95	6.58	6.57
Electricity	9.47	9.24	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82
Natural Gas	3.93	2.53	2.27	2.50	2.88	3.36	3.71	4.32	5.34	6.55

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas = 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas = 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas = 85 percent.
Electricity is assumed to be 100 percent efficient in all sectors.

Table A4-2
Relative Energy Prices by Region and Sector

(Ratio)

Atlantic

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.87	0.92	0.85	0.87	0.87	0.87	0.88	0.94	1.02	1.14
Light Fuel Oil/Electricity	0.78	0.79	0.68	0.68	0.68	0.69	0.69	0.70	0.73	0.77
Natural Gas/Light Fuel Oil	1.12	1.17	1.24	1.28	1.28	1.27	1.27	1.33	1.39	1.48
Commercial										
Natural Gas/Electricity	0.94	1.00	0.92	0.92	0.93	0.93	0.93	0.96	1.01	1.08
Light Fuel Oil/Electricity	0.44	0.43	0.36	0.36	0.36	0.37	0.37	0.38	0.40	0.42
Natural Gas/Light Fuel Oil	2.15	2.31	2.52	2.55	2.56	2.53	2.53	2.55	2.55	2.56
Natural Gas/Heavy Fuel Oil	3.11	3.38	4.22	4.29	4.28	4.21	4.19	4.17	4.02	3.90
Industrial										
Natural Gas/Electricity	0.39	0.37	0.27	0.27	0.27	0.28	0.28	0.29	0.31	0.34
Heavy Fuel Oil/Electricity	0.33	0.32	0.24	0.23	0.23	0.24	0.24	0.25	0.27	0.30
Natural Gas/Heavy Fuel Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.87	0.92	0.88	0.86	0.85	0.87	0.90	0.95	1.03	1.13
Light Fuel Oil/Electricity	0.78	0.79	0.79	0.81	0.84	0.86	0.89	0.95	1.01	1.01
Natural Gas/Light Fuel Oil	1.12	1.17	1.11	1.06	1.01	1.00	1.01	0.99	1.02	1.12
Commercial										
Natural Gas/Electricity	0.94	1.00	0.93	0.92	0.92	0.93	0.95	0.99	1.04	1.11
Light Fuel Oil/Electricity	0.44	0.43	0.43	0.45	0.46	0.48	0.50	0.54	0.58	0.57
Natural Gas/Light Fuel Oil	2.15	2.31	2.15	2.07	1.97	1.94	1.92	1.83	1.81	1.93
Natural Gas/Heavy Fuel Oil	3.11	3.38	3.24	3.06	2.86	2.77	2.70	2.49	2.40	2.56
Industrial										
Natural Gas/Electricity	0.39	0.37	0.27	0.30	0.33	0.35	0.37	0.42	0.49	0.57
Heavy Fuel Oil/Electricity	0.33	0.32	0.81	0.33	0.35	0.37	0.38	0.43	0.47	0.47
Natural Gas/Heavy Fuel Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas 85 percent.
Electricity is assumed to be 100 percenrt efficient in all sectors.

Table A4-2 (Continued)
Relative Energy Prices by Region and Sector

(Ratio)

Quebec

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.85	0.83	0.73	0.76	0.76	0.75	0.76	0.83	0.95	1.11
Light Fuel Oil/Electricity	0.89	0.93	0.78	0.77	0.78	0.78	0.79	0.81	0.85	0.90
Natural Gas/Light Fuel Oil	0.96	0.90	0.95	0.98	0.97	0.95	0.96	1.03	1.12	1.24
Commercial										
Natural Gas/Electricity	0.59	0.57	0.50	0.52	0.52	0.51	0.52	0.57	0.65	0.76
Light Fuel Oil/Electricity	0.58	0.60	0.49	0.49	0.49	0.50	0.50	0.52	0.55	0.59
Natural Gas/Light Fuel Oil	1.01	0.95	1.03	1.04	1.04	1.02	1.03	1.10	1.18	1.29
Natural Gas/Heavy Fuel Oil	1.43	1.20	1.57	1.60	1.59	1.56	1.55	1.64	1.72	1.83
Industrial										
Natural Gas/Electricity	0.66	0.61	0.44	0.44	0.44	0.45	0.45	0.46	0.50	0.55
Heavy Fuel Oil/Electricity	0.49	0.56	0.38	0.38	0.38	0.39	0.39	0.41	0.44	0.49
Natural Gas/Heavy Fuel Oil	1.35	1.09	1.16	1.17	1.16	1.15	1.14	1.14	1.13	1.12

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.85	0.83	0.77	0.74	0.72	0.74	0.78	0.85	0.97	1.10
Light Fuel Oil/Electricity	0.89	0.93	0.92	0.94	0.98	1.01	1.04	1.13	1.21	1.20
Natural Gas/Light Fuel Oil	0.96	0.90	0.84	0.78	0.73	0.73	0.75	0.75	0.80	0.92
Commercial										
Natural Gas/Electricity	0.59	0.57	0.52	0.50	0.49	0.51	0.55	0.60	0.69	0.80
Light Fuel Oil/Electricity	0.58	0.60	0.59	0.62	0.65	0.68	0.70	0.77	0.83	0.83
Natural Gas/Light Fuel Oil	1.01	0.95	0.87	0.80	0.75	0.76	0.78	0.78	0.84	0.97
Natural Gas/Heavy Fuel Oil	1.43	1.20	1.22	1.12	1.03	1.02	1.04	1.02	1.07	1.24
Industrial										
Natural Gas/Electricity	0.66	0.61	0.44	0.48	0.53	0.56	0.60	0.67	0.79	0.93
Heavy Fuel Oil/Electricity	0.49	0.56	0.50	0.53	0.56	0.59	0.62	0.69	0.76	0.76
Natural Gas/Heavy Fuel Oil	1.35	1.09	0.88	0.92	0.94	0.95	0.97	0.97	1.04	1.22

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas 85 percent.
Electricity is assumed to be 100 percenrt efficient in all sectors.

Table A4-2 (Continued)
Relative Energy Prices by Region and Sector

(Ratio)

Ontario

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.69	0.65	0.60	0.62	0.62	0.62	0.63	0.70	0.79	0.93
Light Fuel Oil/Electricity	0.90	0.94	0.80	0.80	0.80	0.81	0.81	0.83	0.86	0.90
Natural Gas/Light Fuel Oil	0.77	0.69	0.74	0.77	0.78	0.77	0.78	0.84	0.92	1.02
Commercial										
Natural Gas/Electricity	0.47	0.43	0.39	0.40	0.40	0.40	0.41	0.45	0.52	0.61
Light Fuel Oil/Electricity	0.61	0.63	0.52	0.51	0.52	0.52	0.52	0.54	0.56	0.60
Natural Gas/Light Fuel Oil	0.78	0.69	0.75	0.77	0.78	0.77	0.78	0.84	0.92	1.02
Natural Gas/Heavy Fuel Oil	1.32	1.10	1.34	1.38	1.39	1.36	1.37	1.45	1.53	1.63
Industrial										
Natural Gas/Electricity	0.56	0.46	0.35	0.35	0.35	0.36	0.36	0.38	0.41	0.46
Heavy Fuel Oil/Electricity	0.44	0.48	0.35	0.35	0.35	0.36	0.36	0.38	0.41	0.46
Natural Gas/Heavy Fuel Oil	1.30	0.95	0.98	1.00	1.00	1.00	1.00	1.00	1.00	1.00

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.69	0.65	0.63	0.61	0.60	0.61	0.65	0.70	0.80	0.92
Light Fuel Oil/Electricity	0.90	0.94	0.92	0.95	0.98	1.01	1.03	1.11	1.18	1.18
Natural Gas/Light Fuel Oil	0.77	0.69	0.68	0.64	0.61	0.61	0.63	0.63	0.68	0.78
Commercial										
Natural Gas/Electricity	0.47	0.43	0.40	0.39	0.38	0.40	0.43	0.47	0.55	0.64
Light Fuel Oil/Electricity	0.61	0.63	0.61	0.63	0.65	0.68	0.70	0.76	0.81	0.81
Natural Gas/Light Fuel Oil	0.78	0.69	0.66	0.62	0.58	0.59	0.61	0.63	0.68	0.79
Natural Gas/Heavy Fuel Oil	1.32	1.10	1.04	0.96	0.88	0.88	0.89	0.87	0.92	1.07
Industrial										
Natural Gas/Electricity	0.56	0.46	0.35	0.39	0.44	0.47	0.51	0.57	0.68	0.81
Heavy Fuel Oil/Electricity	0.44	0.48	0.47	0.49	0.53	0.55	0.58	0.66	0.73	0.73
Natural Gas/Heavy Fuel Oil	1.30	0.95	0.75	0.79	0.83	0.84	0.87	0.86	0.94	1.12

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas 85 percent.
Electricity is assumed to be 100 percenrt efficient in all sectors.

(Ratio)

Manitoba

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.82	0.76	0.64	0.67	0.68	0.68	0.69	0.78	0.92	1.11
Light Fuel Oil/Electricity	1.37	1.26	1.08	1.09	1.09	1.10	1.10	1.12	1.17	1.23
Natural Gas/Light Fuel Oil	0.60	0.60	0.59	0.62	0.62	0.62	0.63	0.70	0.79	0.91
Commercial										
Natural Gas/Electricity	0.43	0.41	0.33	0.35	0.35	0.35	0.36	0.40	0.48	0.58
Light Fuel Oil/Electricity	0.65	0.65	0.51	0.51	0.51	0.51	0.52	0.53	0.56	0.60
Natural Gas/Light Fuel Oil	0.66	0.63	0.66	0.68	0.69	0.68	0.69	0.76	0.86	0.97
Natural Gas/Heavy Fuel Oil	0.81	0.78	1.03	1.07	1.08	1.06	1.07	1.16	1.26	1.37
Industrial										
Natural Gas/Electricity	0.50	0.45	0.27	0.27	0.28	0.28	0.29	0.30	0.34	0.39
Heavy Fuel Oil/Electricity	0.58	0.59	0.36	0.36	0.36	0.37	0.37	0.39	0.42	0.47
Natural Gas/Heavy Fuel Oil	0.86	0.77	0.75	0.76	0.77	0.77	0.77	0.78	0.80	0.82

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.82	0.76	0.68	0.65	0.64	0.66	0.71	0.79	0.93	1.09
Light Fuel Oil/Electricity	1.37	1.26	1.25	1.28	1.32	1.36	1.40	1.50	1.59	1.59
Natural Gas/Light Fuel Oil	0.60	0.60	0.54	0.51	0.48	0.49	0.51	0.53	0.58	0.69
Commercial										
Natural Gas/Electricity	0.43	0.41	0.35	0.33	0.32	0.35	0.38	0.43	0.51	0.61
Light Fuel Oil/Electricity	0.65	0.65	0.61	0.63	0.65	0.68	0.70	0.77	0.83	0.83
Natural Gas/Light Fuel Oil	0.66	0.63	0.57	0.53	0.50	0.51	0.54	0.56	0.62	0.74
Natural Gas/Heavy Fuel Oil	0.81	0.78	0.80	0.73	0.67	0.67	0.70	0.70	0.76	0.91
Industrial										
Natural Gas/Electricity	0.50	0.45	0.27	0.31	0.36	0.39	0.44	0.50	0.62	0.76
Heavy Fuel Oil/Electricity	0.58	0.59	0.48	0.51	0.54	0.57	0.60	0.68	0.76	0.75
Natural Gas/Heavy Fuel Oil	0.86	0.77	0.57	0.62	0.67	0.69	0.72	0.74	0.82	1.00

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas 85 percent.
Electricity is assumed to be 100 percenrt efficient in all sectors.

Table A4-2 (Continued)
Relative Energy Prices by Region and Sector

(Ratio)

Saskatchewan

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.41	0.37	0.34	0.35	0.36	0.36	0.38	0.43	0.51	0.61
Light Fuel Oil/Electricity	0.74	0.76	0.64	0.63	0.64	0.64	0.64	0.66	0.69	0.72
Natural Gas/Light Fuel Oil	0.55	0.49	0.53	0.55	0.56	0.57	0.58	0.65	0.74	0.85
Commercial										
Natural Gas/Electricity	0.21	0.19	0.17	0.18	0.18	0.18	0.19	0.22	0.26	0.31
Light Fuel Oil/Electricity	0.37	0.37	0.30	0.30	0.30	0.30	0.30	0.31	0.33	0.35
Natural Gas/Light Fuel Oil	0.58	0.51	0.56	0.60	0.61	0.61	0.63	0.70	0.79	0.90
Natural Gas/Heavy Fuel Oil	0.71	0.63	0.88	0.94	0.96	0.96	0.98	1.07	1.16	1.27
Industrial										
Natural Gas/Electricity	0.26	0.21	0.18	0.19	0.20	0.20	0.21	0.22	0.24	0.26
Heavy Fuel Oil/Electricity	0.33	0.32	0.20	0.20	0.20	0.20	0.21	0.22	0.24	0.26
Natural Gas/Heavy Fuel Oil	0.78	0.65	0.90	0.96	0.99	0.99	1.00	1.00	1.00	1.00

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.41	0.37	0.35	0.36	0.37	0.40	0.43	0.48	0.57	0.67
Light Fuel Oil/Electricity	0.74	0.76	0.74	0.76	0.79	0.81	0.84	0.90	0.96	0.96
Natural Gas/Light Fuel Oil	0.55	0.49	0.47	0.47	0.47	0.49	0.51	0.53	0.59	0.70
Commercial										
Natural Gas/Electricity	0.21	0.19	0.17	0.18	0.19	0.20	0.22	0.25	0.31	0.37
Light Fuel Oil/Electricity	0.37	0.37	0.36	0.37	0.38	0.40	0.41	0.45	0.48	0.48
Natural Gas/Light Fuel Oil	0.58	0.51	0.49	0.49	0.49	0.51	0.54	0.56	0.63	0.76
Natural Gas/Heavy Fuel Oil	0.71	0.63	0.68	0.67	0.66	0.67	0.70	0.70	0.77	0.92
Industrial										
Natural Gas/Electricity	0.26	0.21	0.19	0.20	0.21	0.23	0.25	0.30	0.37	0.45
Heavy Fuel Oil/Electricity	0.33	0.32	0.27	0.29	0.31	0.32	0.34	0.39	0.43	0.43
Natural Gas/Heavy Fuel Oil	0.78	0.65	0.70	0.69	0.68	0.70	0.75	0.77	0.86	1.05

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas 85 percent.
Electricity is assumed to be 100 percenrt efficient in all sectors.

Table A4-2 (Continued)
Relative Energy Prices by Region and Sector

(Ratio)

Alberta

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.43	0.42	0.41	0.43	0.44	0.45	0.46	0.50	0.60	0.80
Light Fuel Oil/Electricity	0.79	0.87	0.73	0.72	0.73	0.73	0.74	0.75	0.79	0.84
Natural Gas/Light Fuel Oil	0.54	0.49	0.56	0.60	0.61	0.62	0.62	0.66	0.77	0.96
Commercial										
Natural Gas/Electricity	0.24	0.23	0.24	0.26	0.26	0.27	0.28	0.31	0.38	0.50
Light Fuel Oil/Electricity	0.48	0.52	0.44	0.44	0.44	0.45	0.45	0.46	0.49	0.52
Natural Gas/Light Fuel Oil	0.50	0.44	0.54	0.58	0.60	0.61	0.61	0.66	0.78	0.97
Natural Gas/Heavy Fuel Oil	0.73	0.67	1.06	1.16	1.18	1.19	1.20	1.27	1.44	1.71
Industrial										
Natural Gas/Electricity	0.23	0.23	0.21	0.24	0.24	0.25	0.26	0.30	0.34	0.38
Heavy Fuel Oil/Electricity	0.44	0.46	0.29	0.29	0.29	0.29	0.30	0.31	0.34	0.38
Natural Gas/Heavy Fuel Oil	0.52	0.50	0.73	0.82	0.84	0.85	0.87	0.95	1.00	1.00

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.43	0.42	0.42	0.44	0.46	0.49	0.53	0.59	0.69	0.81
Light Fuel Oil/Electricity	0.79	0.87	0.86	0.88	0.91	0.94	0.97	1.06	1.13	1.13
Natural Gas/Light Fuel Oil	0.54	0.49	0.50	0.50	0.50	0.52	0.54	0.56	0.61	0.72
Commercial										
Natural Gas/Electricity	0.24	0.23	0.25	0.26	0.28	0.30	0.33	0.37	0.45	0.54
Light Fuel Oil/Electricity	0.48	0.52	0.53	0.55	0.58	0.60	0.62	0.68	0.73	0.73
Natural Gas/Light Fuel Oil	0.50	0.44	0.47	0.48	0.48	0.50	0.53	0.55	0.61	0.74
Natural Gas/Heavy Fuel Oil	0.73	0.67	0.82	0.83	0.81	0.83	0.86	0.86	0.94	1.14
Industrial										
Natural Gas/Electricity	0.23	0.23	0.23	0.24	0.26	0.29	0.32	0.38	0.48	0.59
Heavy Fuel Oil/Electricity	0.44	0.46	0.39	0.41	0.44	0.47	0.49	0.56	0.62	0.62
Natural Gas/Heavy Fuel Oil	0.52	0.50	0.57	0.59	0.59	0.62	0.66	0.68	0.77	0.96

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:
In the residential sector : light fuel oil = 65 percent; natural gas 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas 85 percent.
Electricity is assumed to be 100 percenrt efficient in all sectors.

Table A4-2 (Continued)
Relative Energy Prices by Region and Sector

(Ratio)

British Columbia and Territories

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.59	0.59	0.58	0.60	0.59	0.58	0.58	0.65	0.79	0.97
Light Fuel Oil/Electricity	0.93	0.97	0.82	0.81	0.82	0.82	0.83	0.84	0.88	0.93
Natural Gas/Light Fuel Oil	0.64	0.61	0.71	0.73	0.72	0.70	0.70	0.78	0.90	1.04
Commercial										
Natural Gas/Electricity	0.40	0.37	0.39	0.40	0.40	0.39	0.39	0.45	0.54	0.67
Light Fuel Oil/Electricity	0.55	0.56	0.49	0.48	0.48	0.49	0.49	0.50	0.53	0.57
Natural Gas/Light Fuel Oil	0.73	0.66	0.79	0.83	0.82	0.80	0.80	0.89	1.02	1.18
Natural Gas/Heavy Fuel Oil	0.88	0.90	1.34	1.40	1.39	1.34	1.34	1.46	1.62	1.80
Industrial										
Natural Gas/Electricity	0.42	0.27	0.26	0.27	0.28	0.30	0.32	0.34	0.37	0.42
Heavy Fuel Oil/Electricity	0.56	0.52	0.36	0.35	0.36	0.36	0.37	0.38	0.42	0.46
Natural Gas/Heavy Fuel Oil	0.74	0.53	0.72	0.76	0.80	0.84	0.88	0.90	0.90	0.90

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Natural Gas/Electricity	0.59	0.59	0.58	0.56	0.55	0.55	0.59	0.65	0.75	0.88
Light Fuel Oil/Electricity	0.93	0.97	0.95	0.97	1.01	1.04	1.07	1.15	1.23	1.23
Natural Gas/Light Fuel Oil	0.64	0.61	0.61	0.58	0.55	0.53	0.55	0.56	0.61	0.72
Commercial										
Natural Gas/Electricity	0.40	0.37	0.38	0.37	0.37	0.38	0.41	0.46	0.54	0.64
Light Fuel Oil/Electricity	0.55	0.56	0.59	0.60	0.63	0.65	0.68	0.74	0.80	0.80
Natural Gas/Light Fuel Oil	0.73	0.66	0.66	0.62	0.58	0.58	0.60	0.61	0.67	0.80
Natural Gas/Heavy Fuel Oil	0.88	0.90	1.00	0.92	0.85	0.83	0.85	0.84	0.90	1.06
Industrial										
Natural Gas/Electricity	0.42	0.27	0.26	0.28	0.33	0.38	0.42	0.49	0.61	0.74
Heavy Fuel Oil/Electricity	0.56	0.52	0.48	0.50	0.53	0.57	0.59	0.67	0.75	0.74
Natural Gas/Heavy Fuel Oil	0.74	0.53	0.54	0.57	0.61	0.67	0.71	0.73	0.81	1.00

Notes: Fuel oils and natural gas prices have been adjusted for the following burner tip efficiencies:

In the residential sector : light fuel oil = 65 percent; natural gas 65 percent.
In the commercial sector : light fuel oil = 70 percent; heavy fuel oil = 72 percent; natural gas 68 percent.
In the industrial sector : heavy fuel oil = 87 percent; natural gas 85 percent.

Electricity is assumed to be 100 percenrt efficient in all sectors.

Table A4-3

Historical Data - Total Energy Demand - End Use by Sector - Primary Demand by Fuel

Canada

(Petajoules)

	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
Sectoral Demand										
Residential	1061.7	1103.1	1149.1	1197.1	1217.3	1298.3	1261.7	1351.8	1346.1	1367.2
Commercial	485.9	546.1	598.2	630.9	662.1	751.0	711.9	744.2	696.7	787.4
Industrial	1323.2	1393.7	1470.1	1546.1	1569.7	1647.9	1774.8	1857.0	1755.5	2036.5
Transportation - Road	822.0	879.0	918.2	970.8	1006.5	1079.0	1181.3	1235.7	1286.2	1361.7
- Air, Rail, Marine	286.3	286.4	290.2	303.8	312.9	333.6	359.4	365.8	338.1	329.7
- Total	1108.3	1165.4	1208.4	1274.5	1319.5	1412.6	1540.7	1601.4	1624.3	1691.4
Non-Energy [a]	208.4	215.3	238.1	287.6	293.6	319.1	362.0	361.2	356.0	396.9
Total End Use	**4187.6**	**4423.5**	**4663.9**	**4936.2**	**5062.1**	**5428.9**	**5651.0**	**5915.7**	**5778.6**	**6279.4**
Own Use	291.2	310.1	321.8	355.1	378.1	412.9	445.6	461.9	471.1	471.2
Electricity and Steam Generation [b][d]	798.0	903.3	942.3	1101.3	1187.3	1290.7	1443.6	1501.3	1525.0	1611.7
Other Conversions	182.5	212.4	190.7	224.0	207.4	210.3	240.3	236.2	222.2	233.2
Total Own Use and Conversions	**1271.7**	**1425.8**	**1454.8**	**1680.4**	**1772.7**	**1914.0**	**2129.6**	**2199.4**	**2218.3**	**2316.1**
Less Electricity, Steam, Coke and Coke Oven Gas	748.5	812.7	840.1	915.9	938.4	1015.5	1103.0	1167.4	1158.3	1227.1
Primary Energy Demand	**4710.8**	**5036.6**	**5278.7**	**5700.8**	**5896.4**	**6327.4**	**6677.6**	**6947.7**	**6838.6**	**7368.4**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	1.7	10.4	6.0	11.8	47.2	74.3	173.2	168.5	144.2	199.7
Hydro [b]	470.2	478.4	527.2	555.7	567.8	631.9	660.9	734.5	707.6	748.1
Oil	2710.3	2886.5	3016.9	3247.3	3309.1	3516.8	3665.1	3763.7	3673.0	3786.5
Natural Gas	807.6	897.6	995.5	1104.1	1216.8	1398.1	1477.8	1568.5	1581.7	1587.5
NGL-Gas Plant	37.4	39.5	45.8	39.3	45.3	53.9	58.9	73.4	67.3	69.6
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6
Coal	602.0	646.1	614.9	674.0	647.6	595.7	584.5	580.7	602.3	654.6
Renewables	81.5	78.1	72.5	68.7	62.6	56.6	57.3	58.4	62.6	319.7

Notes: [a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NLG-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-3 (Continued)
Historical Data - Total Energy Demand - End Use by Sector - Primary Demand by Fuel
Canada

(Petajoules)	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Sectoral Demand										
Residential	1327.5	1382.7	1394.0	1406.6	1334.7	1389.7	1348.2	1342.8	1406.3	1374.1
Commercial	779.0	799.2	809.0	778.6	800.8	826.1	819.0	824.1	821.3	833.1
Industrial	2162.0	2254.5	2393.0	2413.2	2288.1	2127.8	2144.0	2274.9	2369.6	2434.4
Transportation - Road	1406.3	1450.3	1523.0	1544.6	1505.7	1397.2	1363.2	1397.9	1414.5	1434.3
- Air, Rail, Marine	330.9	349.0	403.1	417.2	406.6	347.5	314.7	327.0	320.0	312.7
- Total	1737.2	1799.4	1926.1	1961.8	1912.3	1744.7	1677.9	1724.9	1734.5	1747.0
Non-Energy [a]	462.0	483.5	544.5	524.4	527.2	452.9	495.8	539.6	606.4	597.5
Total End Use	**6467.7**	**6719.3**	**7066.8**	**7084.7**	**6863.0**	**6541.2**	**6485.0**	**6706.2**	**6938.1**	**6986.1**
Own Use	480.1	508.6	520.7	516.1	483.7	459.1	453.0	470.4	470.1	457.3
Electricity and Steam Generation [b][d]	1739.7	1830.0	1969.0	2085.1	2147.4	2182.0	2301.2	2466.8	2575.3	2689.7
Other Conversions	214.2	222.4	251.1	234.4	210.1	182.5	183.1	211.2	202.9	201.5
Total Own Use and Conversions	**2434.0**	**2560.9**	**2740.7**	**2835.7**	**2841.1**	**2823.6**	**2937.2**	**3148.4**	**3248.4**	**3348.5**
Less Electricity, Steam, Coke and Coke Oven Gas	1266.9	1334.6	1415.6	1464.4	1470.9	1463.8	1526.3	1627.3	1670.8	1720.4
Primary Energy Demand	**7634.8**	**7945.6**	**8392.0**	**8456.0**	**8233.2**	**7901.0**	**7896.0**	**8227.3**	**8515.7**	**8614.2**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	301.7	357.7	429.0	455.8	488.4	481.3	570.3	605.3	693.7	803.1
Hydro [b]	768.4	815.0	833.0	844.9	863.7	838.2	866.6	928.3	973.8	1023.0
Oil	3811.9	3901.8	4053.6	3964.6	3705.8	3314.2	3086.8	3063.7	3045.4	3049.6
Natural Gas	1684.8	1744.1	1827.8	1800.8	1774.6	1813.5	1860.0	1976.6	2117.4	2063.9
NGL-Gas Plant	65.2	44.5	59.5	70.3	71.0	65.6	65.1	77.4	86.2	67.5
Ethane	2.6	2.6	13.5	25.3	34.5	22.2	34.6	54.4	68.6	83.7
Coal	681.1	685.3	763.5	823.7	842.3	895.9	925.5	1048.7	1016.2	983.3
Renewables	319.2	394.6	412.1	470.5	452.8	470.1	487.3	473.1	514.4	540.1

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Canada

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	1374.1	1347.5	1404.1	1411.4	1418.4	1435.9	1453.8	1495.2	1545.7	1588.3
Commercial	833.1	825.8	849.3	859.6	873.2	887.0	903.9	941.2	988.1	1031.2
Industrial	2434.4	2484.9	2524.3	2554.9	2561.1	2636.8	2705.1	2857.0	3111.7	3365.7
Transportation - Road	1434.3	1460.3	1464.5	1469.5	1477.9	1495.2	1513.6	1571.5	1648.1	1730.2
- Air, Rail, Marine	312.7	331.1	344.7	353.8	357.2	360.3	362.2	368.4	374.6	388.0
- Total	1747.0	1791.5	1809.2	1823.2	1835.0	1855.5	1875.8	1939.9	2022.7	2118.2
Non-Energy [a]	597.5	663.1	685.7	701.1	713.9	723.7	733.2	812.8	867.4	914.6
Total End Use	**6986.1**	**7112.8**	**7272.6**	**7350.2**	**7401.7**	**7538.9**	**7671.8**	**8046.3**	**8535.5**	**9018.1**
Own Use	457.3	485.0	502.2	507.9	515.6	529.4	538.9	562.8	597.4	620.8
Electricity and Steam Generation [b][d]	2689.7	2855.6	2891.2	2924.7	2937.7	3046.4	3141.3	3388.7	3553.3	3839.6
Other Conversions	201.5	230.6	240.8	246.7	249.8	262.4	274.0	286.7	321.3	358.3
Total Own Use and Conversions	**3348.5**	**3571.2**	**3634.3**	**3679.3**	**3703.1**	**3838.2**	**3954.1**	**4238.2**	**4472.0**	**4818.7**
Less Electricity, Steam, Coke and Coke Oven Gas	1720.4	1793.0	1832.4	1844.3	1856.0	1907.3	1953.9	2058.9	2227.2	2404.4
Primary Energy Demand	**8614.2**	**8891.0**	**9074.4**	**9185.2**	**9248.7**	**9469.8**	**9672.0**	**10225.6**	**10780.2**	**11432.3**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	803.1	882.0	1026.4	1090.7	1116.1	1126.6	1187.6	1314.0	1283.7	1247.2
Hydro [b]	1023.0	998.4	1034.9	1037.2	1042.2	1035.8	1049.6	1086.1	1133.3	1214.7
Oil	3049.6	3170.3	3188.2	3194.2	3205.5	3263.9	3302.2	3390.9	3548.9	3664.1
Natural Gas	2063.9	2046.3	2130.7	2176.8	2211.2	2265.3	2323.7	2489.5	2678.8	2912.9
NGL-Gas Plant	67.5	73.1	81.2	81.9	83.7	83.7	83.9	85.6	87.9	93.6
Ethane	83.7	85.6	85.7	93.7	93.8	93.9	94.1	138.4	139.1	139.7
Coal	983.3	1087.1	962.7	934.7	907.9	1002.6	1021.3	1089.2	1238.6	1469.6
Renewables	540.1	548.1	564.7	575.9	588.4	598.0	609.6	631.9	669.9	690.6

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Canada

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	1374.1	1347.5	1398.3	1404.7	1415.1	1431.5	1445.5	1480.0	1516.9	1548.0
Commercial	833.1	825.8	849.0	863.1	883.4	901.1	919.3	956.9	1007.4	1068.4
Industrial	2434.4	2484.9	2557.9	2653.0	2776.8	2893.0	3016.1	3341.8	3770.5	4133.6
Transportation - Road	1434.3	1460.3	1461.2	1467.1	1478.5	1497.0	1517.3	1581.4	1685.8	1791.1
- Air, Rail, Marine	312.7	331.1	341.1	348.7	353.0	356.5	360.2	370.1	382.3	406.9
- Total	1747.0	1791.5	1802.2	1815.8	1831.5	1853.5	1877.5	1951.5	2068.1	2198.1
Non-Energy [a]	597.5	663.1	686.2	702.3	717.4	727.4	737.1	818.2	878.2	928.4
Total End Use	**6986.1**	**7112.8**	**7293.7**	**7438.9**	**7624.3**	**7806.5**	**7995.5**	**8548.4**	**9241.0**	**9876.5**
Own Use	457.3	485.0	503.2	513.3	527.7	543.5	557.7	586.8	625.6	664.6
Electricity and Steam Generation [b][d]	2689.7	2855.6	2909.6	2980.9	3081.4	3210.8	3343.2	3636.6	3921.2	4328.0
Other Conversions	201.5	230.6	242.0	253.8	266.3	278.2	292.8	316.9	371.4	418.8
Total Own Use and Conversions	**3348.5**	**3571.2**	**3654.8**	**3748.0**	**3875.4**	**4032.5**	**4193.7**	**4540.4**	**4918.2**	**5411.4**
Less Electricity, Steam, Coke and Coke Oven Gas	1720.4	1793.0	1839.5	1873.9	1924.8	1983.9	2055.6	2190.0	2434.6	2701.4
Primary Energy Demand	**8614.2**	**8891.0**	**9109.0**	**9313.0**	**9574.8**	**9855.2**	**10133.7**	**10898.7**	**11724.7**	**12586.5**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	803.1	882.0	1026.3	1094.1	1126.5	1130.4	1203.5	1327.9	1294.0	1405.7
Hydro [b]	1023.0	998.4	1035.0	1043.5	1050.8	1048.3	1056.8	1112.1	1197.3	1342.3
Oil	3049.6	3170.3	3169.7	3180.1	3213.0	3277.9	3321.9	3415.0	3603.4	3755.0
Natural Gas	2063.9	2046.3	2170.4	2268.0	2385.5	2481.1	2571.3	2877.3	3072.8	3231.0
NGL-Gas Plant	67.5	73.1	82.4	84.0	87.3	88.5	89.5	93.6	98.8	104.1
Ethane	83.7	85.6	85.7	93.7	93.8	93.9	94.1	138.4	139.1	139.7
Coal	983.3	1087.1	975.1	972.9	1027.1	1134.1	1183.7	1297.9	1642.1	1907.7
Renewables	540.1	548.1	564.3	576.6	590.9	601.0	613.0	636.4	677.2	701.0

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Atlantic

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	111.5	114.3	115.5	118.0	118.3	120.3	121.7	124.2	127.9	131.7
Commercial	53.9	55.9	56.3	57.0	57.7	58.5	58.9	60.5	64.1	66.1
Industrial	167.2	176.2	179.4	180.1	180.7	185.3	187.5	191.0	203.3	212.4
Transportation - Road	116.7	119.6	121.5	123.6	125.7	128.0	130.0	135.2	141.0	147.1
- Air, Rail, Marine	39.2	44.6	46.9	48.4	49.1	49.5	49.7	50.3	50.2	52.4
- Total	155.9	164.2	168.5	171.9	174.8	177.5	179.8	185.5	191.2	199.4
Non-Energy [a]	15.3	17.3	15.1	15.8	16.0	16.5	16.7	17.3	18.4	19.7
Total End Use	**503.9**	**528.0**	**534.7**	**542.8**	**547.6**	**557.9**	**564.7**	**578.4**	**605.0**	**629.2**
Own Use	35.3	38.9	38.3	38.5	39.4	41.5	41.4	42.4	45.8	46.8
Electricity and Steam Generation [b][d]	298.8	318.6	314.3	314.8	323.4	349.6	380.3	439.5	468.3	475.8
Other Conversions	5.0	13.5	14.0	14.3	14.5	15.2	15.9	16.6	18.6	20.6
Total Own Use and Conversions	**339.0**	**371.1**	**366.7**	**367.7**	**377.3**	**406.3**	**437.6**	**498.5**	**532.7**	**543.2**
Less Electricity, Steam, Coke and Coke Oven Gas	120.4	125.3	130.3	134.6	138.0	143.8	146.6	154.5	167.4	175.1
Primary Energy Demand	**722.6**	**773.7**	**771.1**	**775.9**	**786.9**	**820.5**	**855.7**	**922.4**	**970.2**	**997.4**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	39.9	38.9	37.3	37.3	37.3	37.3	37.3	58.8	58.8	58.8
Hydro [b]	146.4	137.1	148.0	148.0	148.2	148.7	156.8	161.8	161.9	159.0
Oil	370.5	422.6	406.0	402.0	410.6	437.6	447.9	450.2	483.5	498.9
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NGL-Gas Plant	0.5	0.8	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	83.8	91.4	95.2	102.7	104.1	109.4	122.6	157.8	169.8	183.4
Renewables	81.4	82.9	83.9	85.2	86.0	86.7	90.4	93.1	95.4	96.5

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Atlantic

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	111.5	114.3	114.6	116.4	117.2	118.4	119.4	121.2	124.2	128.4
Commercial	53.9	55.9	56.1	56.5	57.1	57.7	58.2	60.8	65.3	69.4
Industrial	167.2	176.2	182.7	187.9	194.9	201.6	207.5	220.8	245.5	265.0
Transportation - Road	116.7	119.6	121.2	123.2	125.6	128.0	130.3	136.9	146.5	155.2
- Air, Rail, Marine	39.2	44.6	46.4	47.6	48.2	48.6	48.8	49.4	50.1	53.6
- Total	155.9	164.2	167.6	170.8	173.8	176.5	179.1	186.3	196.6	208.8
Non-Energy [a]	15.3	17.3	15.0	15.8	16.2	16.5	16.8	17.8	19.3	21.2
Total End Use	**503.9**	**528.0**	**535.9**	**547.5**	**559.1**	**570.8**	**581.2**	**606.9**	**651.0**	**692.8**
Own Use	35.3	38.9	38.6	39.5	41.3	44.4	44.8	47.6	51.8	52.3
Electricity and Steam Generation [b][d]	298.8	318.6	316.7	324.2	341.1	384.7	415.3	486.5	514.2	531.7
Other Conversions	5.0	13.5	14.1	14.8	15.5	16.2	17.0	18.3	21.6	24.3
Total Own Use and Conversions	**339.0**	**371.1**	**369.3**	**378.5**	**398.0**	**445.2**	**477.1**	**552.4**	**587.6**	**608.3**
Less Electricity, Steam, Coke and Coke Oven Gas	120.4	125.3	132.1	138.9	146.3	154.3	160.1	178.5	202.6	217.2
Primary Energy Demand	**722.6**	**773.7**	**773.2**	**787.1**	**810.7**	**861.8**	**898.2**	**980.8**	**1035.9**	**1084.0**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	39.9	38.9	37.3	37.3	37.3	37.3	37.3	58.8	58.8	58.8
Hydro [b]	146.4	137.1	147.9	148.0	148.2	148.7	156.8	161.8	161.9	199.7
Oil	370.5	422.6	408.3	412.8	433.0	473.1	488.1	504.7	535.4	513.9
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NGL-Gas Plant	0.5	0.8	0.7	0.7	0.7	0.7	0.8	0.8	0.9	0.9
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	83.8	91.4	95.2	103.2	105.4	115.2	124.7	161.2	182.4	212.2
Renewables	81.4	82.9	83.9	85.1	86.1	86.7	90.5	93.6	96.5	98.4

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Quebec

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	310.5	305.3	311.9	317.0	320.2	324.7	328.7	336.8	344.5	350.8
Commercial	169.4	169.0	172.9	177.1	180.9	184.7	189.0	198.1	207.4	212.0
Industrial	525.1	547.0	558.4	562.8	569.7	585.6	601.0	633.3	670.2	695.6
Transportation - Road	295.4	297.7	299.4	301.7	305.1	311.2	317.6	338.1	360.0	375.9
- Air, Rail, Marine	65.0	68.5	71.7	73.4	74.0	74.8	75.3	76.8	78.4	81.5
- Total	360.4	366.2	371.0	375.1	379.1	386.0	392.9	414.9	438.3	457.4
Non-Energy [a]	70.0	109.5	110.4	112.9	115.0	118.0	120.6	128.4	140.0	151.9
Total End Use	**1435.4**	**1496.9**	**1524.7**	**1544.9**	**1564.9**	**1598.9**	**1632.2**	**1711.6**	**1800.3**	**1867.6**
Own Use	80.3	78.9	79.6	80.1	81.9	85.8	87.4	89.9	96.6	102.2
Electricity and Steam Generation [b][d]	524.7	546.1	548.3	549.7	552.3	543.3	545.1	576.3	629.8	684.9
Other Conversions	0.0	3.9	4.0	4.0	4.0	4.1	4.2	4.1	4.1	4.1
Total Own Use and Conversions	**605.0**	**628.9**	**631.9**	**633.8**	**638.2**	**633.2**	**636.7**	**670.3**	**730.6**	**791.1**
Less Electricity, Steam, Coke and Coke Oven Gas	540.4	563.2	570.6	569.0	573.0	588.3	602.7	639.8	686.1	734.0
Primary Energy Demand	**1500.0**	**1562.6**	**1585.9**	**1609.7**	**1630.1**	**1643.8**	**1666.3**	**1742.1**	**1844.9**	**1924.7**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	45.9	56.3	61.7	61.7	61.7	61.7	61.7	61.7	61.7	61.7
Hydro [b]	476.4	487.3	483.3	484.6	486.7	475.2	477.0	503.9	545.8	601.4
Oil	654.9	682.9	690.7	699.4	703.9	717.2	725.8	748.1	783.2	793.0
Natural Gas	189.9	202.5	211.7	221.7	230.9	240.9	251.0	273.4	293.8	305.7
NGL-Gas Plant	6.3	3.6	3.9	4.0	6.3	6.5	6.6	7.2	7.8	9.1
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	19.1	23.6	23.8	23.7	23.6	24.1	24.5	24.9	24.8	24.2
Renewables	107.6	106.5	110.8	114.7	116.9	118.3	119.5	122.9	127.7	129.5

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Quebec

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	310.5	305.3	310.6	314.7	318.6	322.1	324.8	329.9	330.6	335.6
Commercial	169.4	169.0	172.4	176.7	180.9	184.5	188.5	197.6	207.0	215.4
Industrial	525.1	547.0	560.6	578.0	602.9	618.7	640.7	678.0	747.6	810.5
Transportation - Road	295.4	297.7	298.3	300.5	303.9	309.4	315.5	334.6	359.4	379.9
- Air, Rail, Marine	65.0	68.5	70.8	72.3	72.9	73.7	74.4	76.5	79.2	84.6
- Total	360.4	366.2	369.1	372.7	376.8	383.1	389.9	411.1	438.6	464.4
Non-Energy [a]	70.0	109.5	110.0	112.7	114.7	117.0	119.6	126.8	139.3	153.6
Total End Use	**1435.4**	**1496.9**	**1522.6**	**1554.9**	**1593.9**	**1625.5**	**1663.5**	**1743.4**	**1863.1**	**1979.5**
Own Use	80.3	78.9	79.2	80.1	82.7	85.3	86.2	89.8	98.3	109.0
Electricity and Steam Generation [b][d]	524.7	546.1	549.2	555.5	559.5	554.4	561.4	602.4	684.1	754.2
Other Conversions	0.0	3.9	4.0	4.1	4.2	4.3	4.5	4.6	4.8	4.8
Total Own Use and Conversions	**605.0**	**628.9**	**632.4**	**639.7**	**646.5**	**644.0**	**652.0**	**696.8**	**787.2**	**868.0**
Less Electricity, Steam, Coke and Coke Oven Gas	540.4	563.2	570.6	574.3	587.6	601.7	619.4	663.6	730.1	811.3
Primary Energy Demand	**1500.0**	**1562.6**	**1584.4**	**1620.3**	**1652.8**	**1667.8**	**1696.2**	**1776.5**	**1920.2**	**2036.2**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	45.9	56.3	61.7	61.7	61.7	61.7	61.7	61.7	61.7	61.7
Hydro [b]	476.4	487.3	484.2	490.4	493.9	486.3	493.3	525.3	595.1	671.7
Oil	654.9	682.9	682.4	688.5	692.6	700.4	706.5	722.7	761.6	792.1
Natural Gas	189.9	202.5	217.3	236.3	255.3	268.1	281.1	308.1	335.7	340.2
NGL-Gas Plant	6.3	3.6	4.1	4.3	6.8	7.1	7.4	8.2	9.2	10.7
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	19.1	23.6	23.9	24.4	25.2	25.6	26.3	27.0	28.1	28.6
Renewables	107.6	106.5	110.9	114.7	117.3	118.6	119.9	123.5	128.7	131.2

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

(Petajoules)

Ontario

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	490.6	480.6	496.0	496.9	500.9	508.7	517.5	536.1	556.8	564.7
Commercial	319.0	317.9	327.6	331.1	337.3	344.1	352.5	367.2	384.9	404.0
Industrial	828.3	848.0	859.7	867.9	862.1	900.7	938.6	999.1	1090.2	1173.8
Transportation - Road	515.7	531.3	542.3	552.6	563.6	578.4	593.0	631.5	670.6	702.5
- Air, Rail, Marine	87.3	89.1	92.4	94.1	94.5	95.2	95.6	96.8	98.5	100.0
- Total	603.0	620.4	634.7	646.8	658.1	673.6	688.5	728.3	769.1	802.5
Non-Energy [a]	228.3	224.1	252.3	256.9	261.2	266.5	272.0	286.2	309.8	333.0
Total End Use	**2469.2**	**2491.0**	**2570.3**	**2599.7**	**2619.5**	**2693.6**	**2769.1**	**2916.9**	**3110.9**	**3278.1**
Own Use	158.0	167.8	174.7	177.4	179.8	184.3	188.0	197.9	210.3	212.6
Electricity and Steam Generation [b][d]	1084.3	1175.7	1242.1	1274.5	1281.4	1371.1	1422.8	1519.8	1546.0	1659.0
Other Conversions	179.0	192.7	200.1	205.0	207.6	218.8	229.0	240.2	271.6	305.3
Total Own Use and Conversions	**1421.3**	**1536.2**	**1616.8**	**1656.9**	**1668.8**	**1774.2**	**1839.8**	**1957.9**	**2027.9**	**2176.9**
Less Electricity, Steam, Coke and Coke Oven Gas	654.0	686.5	705.8	714.6	719.4	745.8	769.0	806.4	869.3	933.6
Primary Energy Demand	**3236.4**	**3340.8**	**3481.3**	**3541.9**	**3568.9**	**3722.0**	**3839.8**	**4068.3**	**4269.4**	**4521.4**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	717.0	786.8	927.4	991.7	1017.1	1027.6	1088.6	1193.5	1163.2	1126.7
Hydro [b]	147.9	123.5	141.5	142.3	142.3	142.3	142.7	142.7	147.6	151.6
Oil	1051.6	1056.6	1090.9	1106.8	1120.3	1144.4	1168.3	1230.5	1292.3	1332.2
Natural Gas	796.5	781.7	808.4	816.8	821.5	849.1	880.5	936.3	1010.4	1072.0
NGL-Gas Plant	16.7	25.7	34.3	34.4	34.7	35.1	35.4	36.3	37.9	40.2
Ethane	4.7	6.7	6.8	6.9	7.0	7.1	7.3	7.7	8.4	9.0
Coal	404.4	461.1	370.5	339.5	320.4	409.2	408.0	408.0	487.0	662.4
Renewables	97.6	98.7	101.5	103.4	105.6	107.3	109.0	113.3	122.6	127.4

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Ontario

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	490.6	480.6	492.6	493.8	498.5	505.5	511.7	524.1	534.7	545.0
Commercial	319.0	317.9	327.0	331.4	339.8	347.2	355.8	366.7	380.5	408.2
Industrial	828.3	848.0	864.2	896.9	929.1	974.5	1032.1	1101.4	1241.4	1376.2
Transportation - Road	515.7	531.3	540.4	550.8	562.8	577.7	592.7	632.9	685.3	731.7
- Air, Rail, Marine	87.3	89.1	91.3	92.9	93.5	94.5	95.5	98.3	101.5	106.3
- Total	603.0	620.4	631.7	643.6	656.3	672.1	688.2	731.2	786.8	838.1
Non-Energy [a]	228.3	224.1	251.3	255.5	259.9	264.8	270.0	283.5	308.1	335.3
Total End Use	**2469.2**	**2491.0**	**2566.8**	**2621.3**	**2683.6**	**2764.1**	**2857.8**	**3007.0**	**3251.6**	**3502.7**
Own Use	158.0	167.8	174.3	178.1	182.7	186.6	192.1	201.2	210.7	223.2
Electricity and Steam Generation [b][d]	1084.3	1175.7	1240.0	1288.4	1349.3	1423.4	1498.6	1563.8	1634.4	1823.9
Other Conversions	179.0	192.7	200.9	211.0	221.7	232.0	244.8	265.6	315.4	359.2
Total Own Use and Conversions	**1421.3**	**1536.2**	**1615.2**	**1677.5**	**1753.7**	**1842.0**	**1935.5**	**2030.6**	**2160.6**	**2406.3**
Less Electricity, Steam, Coke and Coke Oven Gas	654.0	686.5	706.0	725.6	749.0	776.9	811.4	848.1	931.9	1037.2
Primary Energy Demand	**3236.4**	**3340.8**	**3476.0**	**3573.2**	**3688.2**	**3829.2**	**3981.9**	**4189.5**	**4480.3**	**4871.8**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	717.0	786.8	927.3	995.1	1027.5	1031.4	1104.5	1207.4	1173.5	1285.2
Hydro [b]	147.9	123.5	141.5	142.3	142.3	142.3	142.7	144.8	151.3	151.6
Oil	1051.6	1056.6	1080.2	1092.2	1106.9	1125.5	1147.6	1196.0	1264.7	1347.9
Natural Gas	796.5	781.7	814.4	840.9	868.4	905.0	946.1	1016.1	1107.5	1179.2
NGL-Gas Plant	16.7	25.7	34.8	35.3	36.0	36.9	37.3	39.1	41.6	43.7
Ethane	4.7	6.7	6.8	6.9	7.0	7.1	7.3	7.7	8.4	9.0
Coal	404.4	461.1	369.4	356.8	393.9	473.0	486.5	464.1	609.0	724.8
Renewables	97.6	98.7	101.5	103.7	106.2	108.0	109.9	114.3	124.3	130.4

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Manitoba

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	59.2	55.9	60.8	61.2	61.4	62.1	62.6	63.8	66.2	67.7
Commercial	42.3	38.7	42.4	42.6	43.4	44.0	44.7	46.3	47.7	49.3
Industrial	53.4	51.5	53.2	54.4	54.7	56.0	57.2	61.3	66.1	77.3
Transportation - Road	62.2	62.2	61.8	61.6	61.6	61.9	62.2	63.8	67.1	71.7
- Air, Rail, Marine	17.4	18.7	19.1	19.6	19.6	19.8	19.9	20.4	20.9	21.7
- Total	79.5	80.9	80.9	81.2	81.2	81.7	82.2	84.2	88.0	93.3
Non-Energy [a]	8.5	9.6	9.7	9.8	9.9	10.0	10.1	10.4	10.8	11.3
Total End Use	**242.9**	**236.6**	**247.0**	**249.1**	**250.6**	**253.8**	**256.7**	**266.0**	**278.8**	**299.0**
Own Use	22.3	19.5	20.6	20.9	22.3	23.0	24.5	26.6	28.1	29.8
Electricity and Steam Generation [b][d]	64.4	68.1	62.1	62.5	65.7	67.6	68.4	72.2	85.5	91.6
Other Conversions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Own Use and Conversions	**86.6**	**87.6**	**82.7**	**83.5**	**88.0**	**90.6**	**92.9**	**98.8**	**113.6**	**121.5**
Less Electricity, Steam, Coke and Coke Oven Gas	59.1	58.1	60.2	60.6	61.9	62.9	64.7	68.4	73.0	80.8
Primary Energy Demand	**270.5**	**266.1**	**269.5**	**272.0**	**276.7**	**281.5**	**285.0**	**296.5**	**319.5**	**339.6**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	60.6	60.7	60.6	61.1	64.3	66.4	67.2	71.0	82.0	90.4
Oil	100.3	102.5	102.7	103.1	103.0	103.5	104.2	106.9	109.9	115.3
Natural Gas	85.6	75.4	84.4	85.7	87.3	89.4	91.3	96.2	102.6	110.6
NGL-Gas Plant	3.3	3.0	3.1	3.1	3.0	3.0	3.0	2.9	3.0	3.3
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	4.9	8.6	2.6	2.6	2.6	2.6	2.6	2.7	5.1	3.2
Renewables	15.8	15.8	16.1	16.3	16.5	16.6	16.6	16.7	16.9	16.9

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Manitoba

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	59.2	55.9	60.7	61.5	61.8	62.4	62.9	64.3	65.0	64.8
Commercial	42.3	38.7	42.4	42.7	43.7	44.4	45.2	46.5	48.7	51.3
Industrial	53.4	51.5	53.7	55.5	56.8	57.5	59.8	65.7	73.6	84.9
Transportation - Road	62.2	62.2	61.6	61.3	61.2	61.3	61.5	62.8	66.4	71.4
- Air, Rail, Marine	17.4	18.7	19.0	19.3	19.6	19.8	20.0	20.7	21.6	23.0
- Total	79.5	80.9	80.6	80.6	80.8	81.1	81.6	83.6	88.1	94.4
Non-Energy [a]	8.5	9.6	9.6	9.7	9.8	9.9	10.0	10.2	10.7	11.2
Total End Use	**242.9**	**236.6**	**247.0**	**250.0**	**252.9**	**255.3**	**259.4**	**270.3**	**286.0**	**306.6**
Own Use	22.3	19.5	20.7	21.3	23.1	23.8	25.5	26.8	29.7	31.5
Electricity and Steam Generation [b][d]	64.4	68.1	62.2	62.9	67.4	67.9	69.1	73.3	89.1	94.7
Other Conversions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Own Use and Conversions	**86.6**	**87.6**	**83.0**	**84.3**	**90.5**	**91.7**	**94.6**	**100.2**	**118.8**	**126.2**
Less Electricity, Steam, Coke and Coke Oven Gas	59.1	58.1	60.3	61.1	62.6	63.1	65.3	68.6	75.4	84.2
Primary Energy Demand	**270.5**	**266.1**	**269.6**	**273.2**	**280.7**	**283.9**	**288.7**	**301.8**	**329.4**	**348.7**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	60.6	60.7	60.7	61.5	64.6	66.7	67.9	72.1	84.2	93.5
Oil	100.3	102.5	102.0	102.0	101.8	101.6	102.2	104.0	108.5	116.3
Natural Gas	85.6	75.4	85.0	87.5	90.5	93.1	95.9	102.6	109.3	114.4
NGL-Gas Plant	3.3	3.0	3.2	3.2	3.1	3.1	3.2	3.2	3.4	3.7
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	4.9	8.6	2.6	2.6	4.1	2.7	2.7	2.9	6.9	3.6
Renewables	15.8	15.8	16.2	16.4	16.6	16.7	16.7	16.9	17.1	17.2

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Saskatchewan

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	77.6	73.8	79.2	79.8	79.2	79.8	80.4	83.1	86.8	92.3
Commercial	36.3	35.6	37.4	38.1	38.5	38.9	39.5	41.4	43.4	45.7
Industrial	65.1	65.3	68.7	67.0	65.8	67.4	68.7	76.1	86.9	98.0
Transportation - Road	81.5	80.4	77.7	75.5	73.9	72.8	72.0	70.9	73.0	79.5
- Air, Rail, Marine	7.8	8.4	8.5	8.6	8.6	8.6	8.6	8.6	8.6	8.9
- Total	89.3	88.7	86.1	84.1	82.5	81.4	80.5	79.5	81.6	88.4
Non-Energy [a]	10.2	11.4	11.9	11.8	11.8	12.0	12.4	13.6	14.7	16.5
Total End Use	**278.5**	**274.9**	**283.4**	**280.9**	**277.7**	**279.5**	**281.5**	**293.6**	**313.3**	**340.9**
Own Use	39.1	40.3	46.0	47.1	47.6	48.8	49.9	52.0	55.0	57.9
Electricity and Steam Generation [b][d]	120.0	129.6	126.4	120.7	115.2	113.0	115.6	125.7	142.8	146.7
Other Conversions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Own Use and Conversions	**159.1**	**169.9**	**172.4**	**167.8**	**162.8**	**161.8**	**165.5**	**177.7**	**197.8**	**204.6**
Less Electricity, Steam, Coke and Coke Oven Gas	41.6	43.3	46.5	46.3	45.8	46.4	47.0	49.9	55.4	60.5
Primary Energy Demand	**396.0**	**401.5**	**409.2**	**402.4**	**394.6**	**394.9**	**399.9**	**421.4**	**455.7**	**484.9**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	13.6	11.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	19.4
Oil	140.8	141.2	139.6	136.3	134.3	133.5	133.2	135.5	140.9	151.2
Natural Gas	124.2	120.9	133.0	135.7	136.3	139.8	142.9	151.8	164.8	179.1
NGL-Gas Plant	2.7	2.5	2.6	2.5	2.4	2.4	2.4	2.5	2.6	2.7
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	107.6	118.4	113.1	106.8	100.7	98.1	100.2	110.1	125.4	123.8
Renewables	7.2	6.9	7.3	7.5	7.4	7.5	7.6	8.0	8.5	8.7

Notes: [a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Saskatchewan

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	77.6	73.8	79.5	79.6	80.2	80.9	81.5	84.9	91.7	96.6
Commercial	36.3	35.6	37.4	38.1	38.8	39.4	40.0	42.3	45.4	49.2
Industrial	65.1	65.3	69.5	71.9	73.9	76.3	78.6	89.3	104.0	114.7
Transportation - Road	81.5	80.4	77.7	75.7	74.3	73.3	72.6	71.9	75.6	82.9
- Air, Rail, Marine	7.8	8.4	8.4	8.5	8.5	8.6	8.6	8.8	8.8	9.4
- Total	89.3	88.7	86.1	84.2	82.8	81.9	81.2	80.6	84.4	92.3
Non-Energy [a]	10.2	11.4	11.9	12.3	12.5	12.5	12.8	13.9	16.3	17.9
Total End Use	**278.5**	**274.9**	**284.4**	**286.1**	**288.1**	**291.0**	**294.2**	**311.0**	**341.9**	**370.8**
Own Use	39.1	40.3	46.3	48.1	49.6	51.0	52.4	55.2	59.4	62.5
Electricity and Steam Generation [b][d]	120.0	129.6	127.9	125.0	122.4	120.8	124.5	138.6	152.4	172.8
Other Conversions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Own Use and Conversions	**159.1**	**169.9**	**174.2**	**173.1**	**172.0**	**171.8**	**176.9**	**193.8**	**211.8**	**235.3**
Less Electricity, Steam, Coke and Coke Oven Gas	41.6	43.3	47.0	47.6	48.1	48.9	49.9	54.0	62.4	69.0
Primary Energy Demand	**396.0**	**401.5**	**411.6**	**411.6**	**412.0**	**413.9**	**421.2**	**450.8**	**491.3**	**537.1**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	13.6	11.6	13.6	13.6	13.6	13.6	13.6	13.6	19.4	19.4
Oil	140.8	141.2	138.9	136.5	134.6	133.0	132.4	133.4	142.0	156.0
Natural Gas	124.2	120.9	134.6	140.3	146.0	151.4	156.1	170.0	188.5	199.9
NGL-Gas Plant	2.7	2.5	2.6	2.6	2.6	2.7	2.8	3.0	3.2	3.4
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	107.6	118.4	114.5	111.1	107.8	105.7	108.6	122.6	129.4	149.3
Renewables	7.2	6.9	7.4	7.5	7.4	7.6	7.7	8.2	8.8	9.1

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Alberta

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	189.6	179.8	195.6	194.8	194.8	194.4	194.7	199.3	206.8	215.6
Commercial	125.8	120.6	124.4	125.1	124.7	124.6	125.7	130.9	139.5	148.0
Industrial	384.7	369.9	373.4	391.5	397.4	400.9	404.2	426.7	481.4	557.0
Transportation - Road	197.0	199.1	192.1	185.5	179.8	175.1	171.1	163.3	163.2	171.2
- Air, Rail, Marine	312.7	331.1	344.7	353.8	357.2	360.3	362.2	368.4	374.6	388.0
- Total	243.6	247.2	241.4	235.9	230.5	226.1	222.2	215.3	216.3	226.0
Non-Energy [a]	227.7	244.1	240.0	247.2	252.9	252.9	253.0	306.8	319.7	324.1
Total End Use	**1171.4**	**1161.6**	**1174.9**	**1194.4**	**1200.2**	**1199.0**	**1199.8**	**1278.9**	**1363.8**	**1470.5**
Own Use	64.3	70.8	72.7	72.5	71.7	71.4	71.4	72.0	74.9	79.3
Electricity and Steam Generation [b][d]	2689.7	2855.6	2891.2	2924.7	2937.7	3046.4	3141.3	3388.7	3553.3	3839.6
Other Conversions	201.5	230.6	240.8	246.7	249.8	262.4	274.0	286.7	321.3	358.3
Total Own Use and Conversions	**3348.5**	**3571.2**	**3634.3**	**3679.3**	**3703.1**	**3838.2**	**3954.1**	**4238.2**	**4472.0**	**4818.7**
Less Electricity, Steam, Coke and Coke Oven Gas	1720.4	1793.0	1832.4	1844.3	1856.0	1907.3	1953.9	2058.9	2227.2	2404.4
Primary Energy Demand	**1537.6**	**1547.8**	**1536.0**	**1558.9**	**1564.6**	**1568.3**	**1577.5**	**1678.7**	**1804.4**	**1960.2**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	6.5	5.4	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Oil	380.9	394.6	387.2	378.1	368.7	363.0	358.4	354.1	364.2	383.4
Natural Gas	659.3	641.7	662.2	683.5	697.9	697.7	701.6	735.9	800.7	885.7
NGL-Gas Plant	33.3	31.9	30.7	31.8	31.1	30.4	30.0	30.0	29.8	31.1
Ethane	78.9	78.9	78.9	86.8	86.8	86.8	86.8	130.7	130.7	130.7
Coal	355.9	372.2	347.0	347.8	346.4	354.5	363.0	385.2	425.0	472.0
Renewables	22.7	23.1	24.1	25.0	27.7	29.9	31.8	36.9	48.0	51.3

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

Alberta

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	189.6	179.8	195.6	195.3	195.9	197.4	198.8	207.0	219.0	221.8
Commercial	125.8	120.6	125.6	129.2	132.7	136.0	138.6	146.8	158.9	166.3
Industrial	384.7	369.9	397.8	427.8	474.4	504.4	525.4	688.8	813.0	888.4
Transportation - Road	197.0	199.1	193.0	187.8	183.9	181.2	179.2	177.1	183.6	191.4
- Air, Rail, Marine	312.7	331.1	341.1	348.7	353.0	356.5	360.2	370.1	382.3	406.9
- Total	243.6	247.2	241.9	237.7	234.3	232.1	230.6	230.2	238.6	249.9
Non-Energy [a]	227.7	244.1	242.3	249.8	257.4	259.3	259.8	316.2	331.6	331.4
Total End Use	**1171.4**	**1161.6**	**1203.3**	**1239.7**	**1294.7**	**1329.2**	**1353.2**	**1589.1**	**1761.1**	**1857.7**
Own Use	64.3	70.8	73.9	74.6	75.7	76.8	78.0	82.1	87.5	90.7
Electricity and Steam Generation [b][d]	2689.7	2855.6	2909.6	2980.9	3081.4	3210.8	3343.2	3636.6	3921.2	4328.0
Other Conversions	201.5	230.6	242.0	253.8	266.3	278.2	292.8	316.9	371.4	418.8
Total Own Use and Conversions	**3348.5**	**3571.2**	**3654.8**	**3748.0**	**3875.4**	**4032.5**	**4193.7**	**4540.4**	**4918.2**	**5411.4**
Less Electricity, Steam, Coke and Coke Oven Gas	1720.4	1793.0	1839.5	1873.9	1924.8	1983.9	2055.6	2190.0	2434.6	2701.4
Primary Energy Demand	**1537.6**	**1547.8**	**1576.9**	**1621.8**	**1691.5**	**1743.2**	**1788.3**	**2074.9**	**2314.5**	**2469.6**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	6.5	5.4	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Oil	380.9	394.6	391.8	386.3	385.4	387.1	388.3	399.1	425.0	439.8
Natural Gas	659.3	641.7	686.1	722.7	773.6	795.4	810.8	952.0	998.2	1021.5
NGL-Gas Plant	33.3	31.9	31.2	32.1	32.1	31.8	31.7	32.3	32.9	33.8
Ethane	78.9	78.9	78.9	86.8	86.8	86.8	86.8	130.7	130.7	130.7
Coal	355.9	372.2	358.9	363.1	379.9	406.1	432.9	517.6	673.2	785.8
Renewables	22.7	23.1	24.1	25.1	27.8	30.1	32.0	37.2	48.6	52.0

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

British Columbia and Territories

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	135.1	137.6	145.0	143.7	143.7	146.0	148.2	151.9	156.7	165.6
Commercial	86.1	88.1	88.4	88.8	90.8	92.3	93.7	96.8	101.1	106.0
Industrial	410.6	427.0	431.4	431.2	430.7	441.0	447.9	469.6	513.6	551.8
Transportation - Road	166.3	170.2	169.7	168.9	168.2	167.9	167.8	168.8	173.2	182.3
- Air, Rail, Marine	49.5	53.7	56.9	59.2	60.7	61.4	61.9	63.4	65.1	68.8
- Total	215.8	223.9	226.6	228.1	228.9	229.3	229.7	232.2	238.3	251.2
Non-Energy [a]	37.6	47.1	46.3	46.7	47.1	47.8	48.5	50.3	54.0	58.2
Total End Use	**885.2**	**923.7**	**937.7**	**938.5**	**941.2**	**956.3**	**967.9**	**1000.8**	**1063.5**	**1132.8**
Own Use	58.2	68.7	70.4	71.4	72.8	74.7	76.3	82.0	86.6	92.2
Electricity and Steam Generation [b][d]	190.4	193.2	202.2	203.2	202.3	200.4	199.0	217.5	189.6	227.8
Other Conversions	0.0	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.8
Total Own Use and Conversions	**248.6**	**263.7**	**274.4**	**276.4**	**276.9**	**277.0**	**277.2**	**301.3**	**278.1**	**321.9**
Less Electricity, Steam, Coke and Coke Oven Gas	183.6	189.1	190.7	190.4	191.1	194.3	197.2	206.0	225.4	250.6
Primary Energy Demand	**950.2**	**998.4**	**1021.4**	**1024.5**	**1026.9**	**1039.0**	**1047.9**	**1096.1**	**1116.2**	**1204.0**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	171.6	172.7	182.0	181.7	181.2	183.7	186.4	187.2	176.5	187.0
Oil	350.7	369.9	371.1	368.4	364.8	364.7	364.3	365.7	374.8	390.1
Natural Gas	207.7	224.2	230.9	233.4	237.1	248.4	256.4	295.9	306.5	359.8
NGL-Gas Plant	4.9	5.6	5.8	5.5	5.5	5.6	5.7	5.8	6.1	6.3
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	7.5	11.7	10.6	11.5	10.1	4.8	0.4	0.4	1.4	0.5
Renewables	207.8	214.2	220.9	223.9	228.3	231.9	234.8	241.1	250.9	260.2

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-4 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)

British Columbia and Territories

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Sectoral Demand										
Residential	135.1	137.6	144.6	143.3	143.0	144.8	146.4	148.6	151.6	155.8
Commercial	86.1	88.1	88.2	88.5	90.5	91.8	93.0	96.2	101.6	108.7
Industrial	410.6	427.0	429.5	435.0	444.8	459.9	472.0	497.9	545.2	594.0
Transportation - Road	166.3	170.2	169.1	167.9	166.9	166.1	165.5	165.1	169.1	178.6
- Air, Rail, Marine	49.5	53.7	56.2	58.4	59.9	60.6	61.4	63.3	66.0	71.5
- Total	215.8	223.9	225.3	226.3	226.8	226.7	226.9	228.4	235.1	250.1
Non-Energy [a]	37.6	47.1	46.1	46.4	46.9	47.5	48.1	49.7	52.9	57.9
Total End Use	885.2	923.7	933.7	939.5	951.9	970.7	986.3	1020.9	1086.5	1166.4
Own Use	58.2	68.7	70.2	71.5	72.6	75.8	78.8	84.1	88.2	95.4
Electricity and Steam Generation [b][d]	190.4	193.2	201.5	203.7	204.3	202.9	192.3	227.5	209.0	238.7
Other Conversions	0.0	1.8	1.8	1.9	1.9	2.0	2.0	2.1	2.2	2.1
Total Own Use and Conversions	248.6	263.7	273.5	277.1	278.8	280.6	273.1	313.7	299.3	336.2
Less Electricity, Steam, Coke and Coke Oven Gas	183.6	189.1	190.0	190.7	191.8	195.9	200.2	210.1	232.7	263.5
Primary Energy Demand	950.2	998.4	1017.1	1025.8	1038.9	1055.4	1059.3	1124.5	1153.1	1239.1
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	171.6	172.7	181.2	181.8	182.3	184.8	176.6	188.6	179.5	200.5
Oil	350.7	369.9	366.1	361.9	358.6	357.1	356.8	355.2	366.2	388.9
Natural Gas	207.7	224.2	233.0	240.3	251.6	268.1	281.2	328.4	333.5	375.8
NGL-Gas Plant	4.9	5.6	5.9	5.8	6.0	6.2	6.5	6.9	7.6	7.8
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	7.5	11.7	10.5	11.8	10.9	5.9	1.9	2.6	13.0	3.4
Renewables	207.8	214.2	220.3	224.2	229.6	233.2	236.2	242.8	253.3	262.7

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL- Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A4-5
Historical Data - End Use Demand by Fuel and Sector - Canada

(Petajoules)	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
Residential										
Electricity	127.2	137.3	147.0	157.8	169.1	182.5	196.4	215.7	233.3	257.7
Oil	545.8	574.2	592.8	625.4	621.0	653.3	616.6	648.1	619.1	607.1
Natural Gas	234.7	249.7	269.5	282.8	298.1	336.0	328.1	353.3	364.0	383.1
Propane	42.8	40.5	48.0	47.1	55.4	57.7	55.1	69.7	62.5	50.9
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	81.5	78.1	72.5	68.7	62.6	56.6	57.3	58.4	62.6	64.9
Other	29.8	23.4	19.3	15.3	11.1	12.3	8.2	6.6	4.6	3.5
Total	**1061.7**	**1103.1**	**1149.1**	**1197.1**	**1217.3**	**1298.3**	**1261.7**	**1351.8**	**1346.1**	**1367.2**
Commercial										
Electricity	102.8	113.3	128.6	141.4	154.3	184.8	203.0	220.9	231.6	254.8
Oil	242.4	278.6	287.8	301.9	300.3	319.7	279.6	266.0	205.8	254.9
Natural Gas	120.6	136.6	166.3	175.5	199.2	241.2	227.8	255.9	259.3	277.7
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	20.2	17.5	15.5	12.1	8.3	5.3	1.6	1.5	0.0	0.0
Total	**485.9**	**546.1**	**598.2**	**630.9**	**662.1**	**751.0**	**711.9**	**744.2**	**696.7**	**787.4**
Industrial										
Electricity	312.6	328.8	348.6	364.8	375.2	390.9	417.1	435.5	392.0	405.8
Oil	393.5	408.2	447.9	477.4	477.3	503.5	542.0	553.9	539.4	528.6
Natural Gas	297.4	332.7	388.7	420.9	477.4	515.7	556.4	613.5	584.7	598.7
Coal, Coke and Coke Oven Gas	315.1	318.2	277.5	276.6	232.1	227.8	247.8	241.7	228.2	237.8
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.8
Propane	4.5	5.9	7.4	6.4	7.8	10.0	11.3	12.4	11.1	10.8
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1323.2**	**1393.7**	**1470.1**	**1546.1**	**1569.7**	**1647.9**	**1774.8**	**1857.0**	**1755.5**	**2036.5**
Non-Energy										
Asphalt	85.2	89.8	94.8	103.3	108.2	120.3	137.9	130.1	133.1	124.0
Lubes and Greases	28.7	29.3	30.4	30.6	32.8	34.3	38.3	39.4	37.2	38.8
Naphtha	12.0	12.4	13.4	12.8	13.1	16.1	23.1	15.8	14.8	14.8
Petroleum Coke	19.9	20.3	24.5	24.5	16.4	16.0	23.4	27.2	21.9	24.7
Natural Gas	19.7	21.6	26.7	34.8	37.3	37.7	40.8	42.9	49.9	59.6
Oil	40.5	39.0	45.6	78.1	75.8	79.9	81.5	82.0	68.4	84.0
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	11.3
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	13.1
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6
Other Oil	2.3	3.0	2.6	3.4	10.0	14.8	17.0	23.8	27.1	24.0
Total	**208.4**	**215.3**	**238.1**	**287.6**	**293.6**	**319.1**	**362.0**	**361.2**	**356.0**	**396.9**
Transportation										
Motor Gasoline	788.3	841.7	874.0	922.4	954.9	1021.6	1106.1	1147.1	1191.4	1220.5
Diesel Fuel Oil	141.2	147.1	154.7	157.3	166.8	181.2	200.8	224.6	214.6	261.2
Aviation Turbo - Total	68.8	76.5	86.4	94.9	98.0	103.4	118.4	130.5	138.2	137.1
Aviation Gasoline	9.9	9.4	8.7	7.7	7.5	7.7	8.0	7.8	7.8	7.8
Heavy Fuel Oil	83.5	78.6	72.2	79.3	81.6	88.8	93.9	81.9	66.7	63.9
Other	16.7	12.0	12.5	13.0	10.6	9.9	13.5	9.5	5.5	0.9
Total	**1108.3**	**1165.4**	**1208.4**	**1274.5**	**1319.5**	**1412.6**	**1540.7**	**1601.4**	**1624.3**	**1691.4**
Total End Use										
Electricity	542.6	579.4	624.2	664.0	698.7	758.2	816.5	872.0	856.9	918.3
Oil	2466.7	2612.3	2739.8	2923.0	2968.3	3165.7	3295.3	3384.2	3289.7	3391.4
Natural Gas	672.3	740.5	851.2	914.0	1012.0	1130.6	1153.1	1265.6	1257.9	1319.1
Coal, Coke and Coke Oven Gas	377.2	366.9	320.7	313.0	257.4	250.0	262.5	253.3	234.3	242.2
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	81.5	78.1	72.5	68.7	62.6	56.6	57.3	58.4	62.6	64.9
Wood Waste	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.8
Other	47.3	46.4	55.4	53.5	63.2	67.7	66.4	82.1	77.3	88.8
Total	**4187.6**	**4423.5**	**4663.9**	**4936.2**	**5062.1**	**5428.9**	**5651.0**	**5915.7**	**5778.6**	**6279.4**

Table A4-5 (Continued)
Historical Data - End Use Demand by Fuel and Sector - Canada

(Petajoules)	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Residential										
Electricity	278.9	313.8	319.1	337.5	344.5	359.6	377.2	395.3	411.3	428.1
Oil	546.9	529.1	518.6	497.9	404.1	373.7	328.4	280.1	281.5	273.7
Natural Gas	387.9	435.1	447.9	458.6	463.7	520.2	505.0	524.5	562.9	524.8
Propane	49.8	32.0	30.8	31.6	29.9	34.5	34.0	34.4	36.5	32.4
Butanes	0.0	0.0	0.0	0.1	0.4	0.6	0.4	0.0	0.0	0.0
Wood	60.4	68.5	73.5	77.5	88.1	97.1	100.0	103.0	107.9	109.0
Other	3.6	4.1	4.2	3.4	4.0	4.0	3.2	5.5	6.2	6.1
Total	**1327.5**	**1382.7**	**1394.0**	**1406.6**	**1334.7**	**1389.7**	**1348.2**	**1342.8**	**1406.3**	**1374.1**
Commercial										
Electricity	260.1	247.0	261.9	257.4	268.3	276.4	287.8	294.9	304.4	325.9
Oil	223.2	239.9	210.5	202.6	192.3	172.1	161.0	145.9	107.7	103.8
Natural Gas	295.8	312.4	320.9	301.3	323.0	356.1	351.1	364.1	388.6	386.1
Propane	0.0	0.0	14.6	14.7	15.2	18.8	17.0	16.4	17.9	14.6
Butanes	0.0	0.0	0.0	0.4	0.4	0.3	0.1	0.0	0.0	0.0
Other	0.0	0.0	1.1	2.2	1.5	2.3	2.0	2.8	2.6	2.7
Total	**779.0**	**799.2**	**809.0**	**778.6**	**800.8**	**826.1**	**819.0**	**824.1**	**821.3**	**833.1**
Industrial										
Electricity	447.7	470.1	476.7	503.9	523.9	490.4	513.2	576.6	616.2	632.6
Oil	560.1	530.7	545.6	509.4	452.5	371.3	321.6	319.3	281.3	312.8
Natural Gas	651.4	669.4	724.6	728.1	688.4	640.9	659.4	730.2	787.3	795.8
Coal, Coke and Coke Oven Gas	187.6	241.6	250.0	248.3	226.4	205.2	216.4	240.1	246.3	236.6
Steam	0.0	0.0	43.2	42.0	45.2	62.2	49.9	45.8	33.3	31.6
Wood Waste	258.7	326.1	338.6	367.5	338.8	345.4	371.5	350.7	388.5	409.5
Propane	11.8	16.6	14.4	13.3	12.4	12.1	10.5	10.8	15.6	13.9
Butanes	0.0	0.0	0.0	0.7	0.5	0.4	1.6	1.6	1.2	1.7
Other	44.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**2162.0**	**2254.5**	**2393.0**	**2413.2**	**2288.1**	**2127.8**	**2144.0**	**2274.9**	**2369.6**	**2434.4**
Non-Energy										
Asphalt	137.2	138.4	146.5	140.0	128.3	108.3	112.0	105.3	119.7	122.7
Lubes and Greases	38.4	40.3	41.9	41.5	40.5	34.5	34.6	36.3	36.1	37.8
Naphtha	16.8	15.7	20.3	19.2	18.5	13.7	14.6	10.3	10.3	10.3
Petroleum Coke	31.4	30.9	25.9	34.3	35.9	24.8	27.4	31.4	28.1	40.1
Natural Gas	83.9	88.1	89.5	94.4	96.2	105.8	141.8	156.4	174.5	148.7
Oil	96.3	137.2	172.4	137.8	138.8	112.8	104.7	116.2	134.1	126.9
Propane	11.4	6.7	10.1	9.2	7.3	6.3	10.9	12.2	16.3	8.4
Butanes	14.0	6.7	9.8	8.0	9.5	5.1	6.8	9.8	11.3	7.1
Ethane	2.6	2.6	13.5	25.3	34.5	22.2	34.6	54.4	68.6	83.7
Other Oil	30.0	16.8	14.6	14.8	17.6	19.3	8.6	7.3	7.6	11.7
Total	**462.0**	**483.5**	**544.5**	**524.4**	**527.2**	**452.9**	**495.8**	**539.6**	**606.4**	**597.5**
Transportation										
Motor Gasoline	1240.6	1283.4	1328.0	1333.5	1290.3	1187.9	1150.6	1140.8	1134.5	1138.7
Diesel Fuel Oil	288.1	293.3	332.5	350.1	345.1	322.9	315.4	363.9	382.9	383.0
Aviation Turbo - Total	138.1	143.7	163.2	164.4	160.4	145.9	140.3	148.9	154.5	156.9
Aviation Gasoline	7.9	8.3	8.1	8.0	7.5	6.0	5.9	5.9	5.9	5.6
Heavy Fuel Oil	61.6	68.1	90.4	102.0	104.7	76.4	56.2	50.1	39.7	41.6
Other	0.8	2.6	4.0	3.8	4.2	5.7	9.5	15.3	17.0	21.2
Total	**1737.2**	**1799.4**	**1926.1**	**1961.8**	**1912.3**	**1744.7**	**1677.9**	**1724.9**	**1734.5**	**1747.0**
Total End Use										
Electricity	986.7	1032.7	1059.3	1100.7	1139.2	1128.9	1181.1	1269.4	1334.7	1389.4
Oil	3416.7	3475.8	3618.5	3555.4	3336.5	2969.5	2781.2	2761.6	2723.7	2765.7
Natural Gas	1418.9	1505.0	1583.0	1582.4	1571.3	1623.0	1657.4	1775.4	1913.9	1856.2
Coal, Coke and Coke Oven Gas	187.6	246.6	255.2	252.8	231.4	210.6	220.8	244.5	251.0	241.2
Steam	0.0	0.0	43.8	43.1	45.7	63.2	50.6	46.4	34.0	32.2
Wood	60.4	68.5	73.5	77.5	88.1	97.1	100.0	103.0	107.9	109.0
Wood Waste	258.7	326.1	338.6	367.5	338.8	345.4	371.5	350.7	388.5	409.5
Other	138.7	64.6	94.9	105.1	111.9	103.5	122.4	155.1	184.4	182.8
Total	**6467.7**	**6719.3**	**7066.8**	**7084.7**	**6863.0**	**6541.2**	**6485.0**	**6706.2**	**6938.1**	**6986.1**

Table A4-6

End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Canada Low Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	428.1	443.1	467.0	476.6	483.1	495.8	505.4	529.6	551.5	576.7
Oil	273.7	256.1	245.2	236.6	232.2	225.5	221.7	216.2	205.5	195.0
Natural Gas	524.8	506.4	543.6	548.3	553.6	562.0	572.2	589.5	619.0	640.5
Propane	32.4	31.0	32.4	31.9	31.5	31.8	32.1	32.8	33.4	34.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	109.0	105.1	110.0	112.2	112.5	115.1	116.8	121.4	130.6	135.6
Other	6.1	5.9	5.9	5.8	5.6	5.6	5.7	5.8	5.7	6.2
Total	**1374.1**	**1347.5**	**1404.1**	**1411.4**	**1418.4**	**1435.9**	**1453.8**	**1495.2**	**1545.7**	**1588.3**
Commercial										
Electricity	325.9	337.0	343.4	345.3	351.0	355.2	360.8	372.5	392.7	414.9
Oil	103.8	100.5	98.0	97.8	96.2	96.5	96.1	95.5	94.9	89.9
Natural Gas	386.1	370.5	389.5	397.9	406.8	416.2	427.7	453.4	480.3	505.6
Propane	14.6	15.2	15.6	15.7	15.9	16.0	16.1	16.5	16.4	16.7
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	2.7	2.6	2.8	2.9	3.3	3.1	3.2	3.4	3.7	4.0
Total	**833.1**	**825.8**	**849.3**	**859.6**	**873.2**	**887.0**	**903.9**	**941.2**	**988.1**	**1031.2**
Industrial										
Electricity	632.6	653.7	657.5	654.0	649.5	668.4	688.6	741.2	817.1	903.2
Oil	312.8	325.8	336.2	336.9	329.4	335.7	339.1	337.2	339.9	326.0
Natural Gas	795.8	785.4	794.9	817.9	828.5	856.6	884.8	959.7	1080.0	1209.2
Coal, Coke and Coke Oven Gas	236.6	254.6	263.3	268.7	271.3	290.5	304.2	324.3	361.7	401.0
Steam	31.6	30.1	28.4	26.8	24.7	24.0	23.1	20.9	24.7	28.5
Wood Waste	409.5	418.7	425.8	431.2	437.6	440.4	443.3	449.1	459.0	465.2
Propane	13.9	13.8	13.8	13.6	13.1	13.3	13.4	13.6	13.9	13.9
Butanes	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.6
Other	0.0	1.4	2.8	4.2	5.6	6.4	7.2	9.5	13.8	17.2
Total	**2434.4**	**2484.9**	**2524.3**	**2554.9**	**2561.1**	**2636.8**	**2705.1**	**2857.0**	**3111.7**	**3365.7**
Non-Energy										
Asphalt	122.7	133.4	128.7	128.2	127.7	130.2	132.4	139.2	151.7	164.6
Lubes and Greases	37.8	39.5	42.3	44.6	46.5	48.5	50.5	54.6	59.7	63.1
Naphtha	10.3	10.1	11.4	12.2	12.9	13.7	14.5	16.3	18.3	18.9
Petroleum Coke	40.1	44.8	45.5	46.2	46.9	47.7	48.4	50.8	55.1	59.8
Natural Gas	148.7	159.4	159.4	159.4	165.8	165.8	165.8	173.6	181.4	181.4
Oil	126.9	151.3	164.9	168.1	168.6	171.5	174.3	183.6	200.3	218.6
Propane	8.4	13.4	21.7	21.9	22.9	23.2	23.3	24.2	25.7	27.6
Butanes	7.1	4.6	4.6	4.7	6.0	6.1	6.1	6.3	6.7	7.0
Ethane	83.7	85.6	85.7	93.7	93.8	93.9	94.1	138.4	139.1	139.7
Other Oil	11.7	21.0	21.5	22.1	22.6	23.2	23.8	25.7	29.5	34.0
Total	**597.5**	**663.1**	**685.7**	**701.1**	**713.9**	**723.7**	**733.2**	**812.8**	**867.4**	**914.6**
Transportation										
Motor Gasoline	1138.7	1150.9	1140.8	1132.8	1129.8	1135.5	1143.1	1174.8	1220.2	1267.9
Diesel Fuel Oil	383.0	403.9	420.7	438.2	450.7	463.6	475.0	503.9	534.4	570.7
Aviation Turbo - Total	156.9	167.1	175.4	178.0	179.3	179.7	179.8	179.6	182.5	186.0
Aviation Gasoline	5.6	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Heavy Fuel Oil	41.6	40.2	41.8	42.4	42.3	42.6	42.7	42.8	40.9	41.2
Other	21.2	23.5	24.7	25.9	27.0	28.2	29.4	33.0	38.9	46.6
Total	**1747.0**	**1791.5**	**1809.2**	**1823.2**	**1835.0**	**1855.5**	**1875.8**	**1939.9**	**2022.7**	**2118.2**
Total End Use										
Electricity	1389.4	1436.7	1471.1	1479.3	1487.4	1523.5	1559.0	1648.4	1767.6	1902.5
Oil	2765.7	2850.4	2878.2	2890.0	2891.1	2919.7	2947.1	3026.1	3138.7	3241.3
Natural Gas	1856.2	1823.9	1890.2	1927.0	1958.7	2005.3	2055.8	2183.4	2371.1	2550.2
Coal, Coke and Coke Oven Gas	241.2	258.9	267.4	272.6	275.0	294.1	307.8	327.9	364.9	404.1
Steam	32.2	30.8	29.1	27.4	25.2	24.3	23.4	21.3	25.0	28.8
Wood	109.0	105.1	110.0	112.2	112.5	115.1	116.8	121.4	130.6	135.6
Wood Waste	409.5	418.7	425.8	431.2	437.6	440.4	443.3	449.1	459.0	465.2
Other	182.8	188.2	200.7	210.4	214.3	216.5	218.5	268.8	278.5	290.3
Total	**6986.1**	**7112.8**	**7272.6**	**7350.2**	**7401.7**	**7538.9**	**7671.8**	**8046.3**	**8535.5**	**9018.1**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

Canada

High Case

(Petajoules)	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	428.1	443.1	465.0	474.3	481.3	494.4	504.0	524.4	544.9	572.1
Oil	273.7	256.1	244.3	236.3	231.8	220.8	213.3	193.8	172.2	163.9
Natural Gas	524.8	506.4	541.3	545.1	553.0	564.6	574.9	603.9	633.9	640.8
Propane	32.4	31.0	32.3	31.9	31.5	31.9	32.1	32.7	33.2	33.9
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	109.0	105.1	109.5	111.4	111.9	114.2	115.4	119.3	126.9	131.3
Other	6.1	5.9	5.9	5.8	5.6	5.6	5.7	5.8	5.8	6.1
Total	**1374.1**	**1347.5**	**1398.3**	**1404.7**	**1415.1**	**1431.5**	**1445.5**	**1480.0**	**1516.9**	**1548.0**
Commercial										
Electricity	325.9	337.0	343.4	345.3	351.7	357.7	365.5	379.4	407.0	445.3
Oil	103.8	100.5	96.4	95.6	93.2	90.8	88.5	82.7	79.2	81.4
Natural Gas	386.1	370.5	390.7	403.5	419.0	432.8	445.2	473.8	498.9	518.6
Propane	14.6	15.2	15.6	15.9	16.2	16.4	16.7	17.2	17.3	17.8
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	2.7	2.6	2.8	2.9	3.3	3.2	3.4	3.8	5.0	5.3
Total	**833.1**	**825.8**	**849.0**	**863.1**	**883.4**	**901.1**	**919.3**	**956.9**	**1007.4**	**1068.4**
Industrial										
Electricity	632.6	653.7	664.8	676.7	699.3	725.1	762.2	835.3	961.5	1093.2
Oil	312.8	325.8	326.4	324.5	324.0	329.2	336.2	332.1	349.0	372.2
Natural Gas	795.8	785.4	829.3	894.3	973.7	1035.1	1091.3	1270.6	1385.2	1486.9
Coal, Coke and Coke Oven Gas	236.6	254.6	264.5	276.9	290.3	310.1	328.4	397.6	544.9	632.4
Steam	31.6	30.1	28.6	27.8	26.9	26.3	25.9	23.4	28.4	33.9
Wood Waste	409.5	418.7	425.9	432.6	440.3	443.7	447.0	454.3	466.8	475.5
Propane	13.9	13.8	14.0	14.1	14.4	14.8	15.3	15.9	16.8	17.0
Butanes	1.7	1.6	1.7	1.7	1.7	1.8	1.8	1.9	2.1	2.1
Other	0.0	1.4	2.8	4.4	6.0	6.9	7.9	10.6	15.7	20.4
Total	**2434.4**	**2484.9**	**2557.9**	**2653.0**	**2776.8**	**2893.0**	**3016.1**	**3341.8**	**3770.5**	**4133.6**
Non-Energy										
Asphalt	122.7	133.4	130.6	132.0	134.9	138.7	142.0	152.8	172.3	185.9
Lubes and Greases	37.8	39.5	41.4	43.0	44.3	45.7	47.1	49.8	53.9	58.8
Naphtha	10.3	10.1	10.9	11.2	11.4	11.8	12.2	13.0	14.3	15.7
Petroleum Coke	40.1	44.8	45.5	46.2	46.9	47.7	48.4	50.8	55.1	59.8
Natural Gas	148.7	159.4	159.4	159.4	165.8	165.8	165.8	173.6	181.4	181.4
Oil	126.9	151.3	164.9	168.1	168.6	171.5	174.3	183.6	200.3	218.6
Propane	8.4	13.4	21.7	21.9	22.9	23.2	23.3	24.2	25.7	27.6
Butanes	7.1	4.6	4.6	4.7	6.0	6.1	6.1	6.3	6.7	7.0
Ethane	83.7	85.6	85.7	93.7	93.8	93.9	94.1	138.4	139.1	139.7
Other Oil	11.7	21.0	21.5	22.1	22.6	23.2	23.8	25.7	29.5	34.0
Total	**597.5**	**663.1**	**686.2**	**702.3**	**717.4**	**727.4**	**737.1**	**818.2**	**878.2**	**928.4**
Transportation										
Motor Gasoline	1138.7	1150.9	1138.1	1130.9	1129.6	1135.0	1142.6	1173.9	1230.3	1284.9
Diesel Fuel Oil	383.0	403.9	418.9	434.0	447.6	460.5	472.9	504.9	551.0	604.3
Aviation Turbo - Total	156.9	167.1	172.4	175.8	177.8	179.4	181.6	186.9	191.8	202.5
Aviation Gasoline	5.6	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Heavy Fuel Oil	41.6	40.2	41.4	41.6	41.0	41.0	40.8	40.0	38.9	40.0
Other	21.2	23.5	25.5	27.6	29.6	31.7	33.7	39.9	50.1	60.5
Total	**1747.0**	**1791.5**	**1802.2**	**1815.8**	**1831.5**	**1853.5**	**1877.5**	**1951.5**	**2068.1**	**2198.1**
Total End Use										
Electricity	1389.4	1436.7	1476.6	1499.9	1536.3	1581.3	1636.3	1744.7	1920.4	2119.1
Oil	2765.7	2850.4	2858.5	2867.2	2879.8	2901.2	2929.7	2995.9	3143.7	3327.7
Natural Gas	1856.2	1823.9	1923.8	2006.2	2116.4	2204.1	2283.8	2531.1	2713.0	2845.7
Coal, Coke and Coke Oven Gas	241.2	258.9	268.6	280.7	293.9	313.8	332.1	401.2	548.2	635.5
Steam	32.2	30.8	29.3	28.5	27.4	26.7	26.2	23.8	28.7	34.2
Wood	109.0	105.1	109.5	111.4	111.9	114.2	115.4	119.3	126.9	131.3
Wood Waste	409.5	418.7	425.9	432.6	440.3	443.7	447.0	454.3	466.8	475.5
Other	182.8	188.2	201.5	212.4	218.2	221.6	225.0	278.2	293.3	307.4
Total	**6986.1**	**7112.8**	**7293.7**	**7438.9**	**7624.3**	**7806.5**	**7995.5**	**8548.4**	**9241.0**	**9876.5**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Atlantic Low Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	32.1	33.4	34.7	36.1	37.1	38.4	38.9	41.1	42.6	43.6
Oil	48.0	49.0	49.0	49.8	49.2	49.2	49.8	49.1	50.3	51.7
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane	1.6	1.6	1.7	1.8	1.8	1.8	1.8	1.9	1.9	2.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	28.3	28.9	28.6	28.9	29.0	29.5	29.9	30.6	31.6	32.6
Other	1.5	1.4	1.4	1.4	1.3	1.4	1.4	1.4	1.4	1.8
Total	**111.5**	**114.3**	**115.5**	**118.0**	**118.3**	**120.3**	**121.7**	**124.2**	**127.9**	**131.7**
Commercial										
Electricity	20.1	20.6	21.5	22.5	23.4	24.1	24.8	26.1	28.8	31.1
Oil	31.8	33.1	32.7	32.3	32.1	32.1	31.7	31.9	32.6	32.2
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane	1.5	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.1	2.1
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Total	**53.9**	**55.9**	**56.3**	**57.0**	**57.7**	**58.5**	**58.9**	**60.5**	**64.1**	**66.1**
Industrial										
Electricity	45.4	46.1	48.2	49.5	50.5	53.1	54.8	57.8	63.3	65.8
Oil	57.6	64.0	64.0	62.3	61.0	61.9	61.7	61.0	64.9	69.3
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, Coke and Coke Oven Gas	12.7	13.8	14.3	14.6	14.8	15.6	16.3	17.1	19.3	21.6
Steam	1.3	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Wood Waste	49.4	50.1	50.6	51.3	51.9	52.0	52.0	52.2	52.5	52.2
Propane	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.1	0.3	0.4	0.5	0.6	0.6	0.8	1.2	1.2
Total	**167.2**	**176.2**	**179.4**	**180.1**	**180.7**	**185.3**	**187.5**	**191.0**	**203.3**	**212.4**
Non-Energy										
Asphalt	10.2	10.8	11.0	11.1	11.2	11.5	11.6	11.9	12.7	13.9
Lubes and Greases	2.1	2.2	2.5	2.7	2.9	3.0	3.1	3.4	3.6	3.7
Naphtha	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Petroleum Coke	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	2.7	4.0	1.2	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**15.3**	**17.3**	**15.1**	**15.8**	**16.0**	**16.5**	**16.7**	**17.3**	**18.4**	**19.7**
Transportation										
Motor Gasoline	93.8	96.1	95.9	95.8	96.2	96.8	97.5	99.2	101.1	104.1
Diesel Fuel Oil	38.5	42.1	45.5	48.8	51.3	53.4	55.2	59.8	64.6	69.8
Aviation Turbo-Total	16.5	17.7	18.5	18.6	18.5	18.5	18.3	18.0	17.7	18.0
Aviation Gasoline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Heavy Fuel Oil	6.3	7.5	7.8	7.9	7.9	7.8	7.8	7.6	6.9	6.5
Other	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
Total	**155.9**	**164.2**	**168.5**	**171.9**	**174.8**	**177.5**	**179.8**	**185.5**	**191.2**	**199.4**
Total End Use										
Electricity	97.6	100.1	104.4	108.0	110.9	115.6	118.4	125.0	134.7	140.5
Oil	308.2	327.3	328.7	331.7	332.6	336.6	339.2	344.3	356.9	371.8
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, Coke and Coke Oven Gas	14.3	15.3	15.8	16.1	16.3	17.1	17.8	18.6	20.6	22.9
Steam	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2
Wood	28.3	28.9	28.6	28.9	29.0	29.5	29.9	30.6	31.6	32.6
Wood Waste	49.4	50.1	50.6	51.3	51.9	52.0	52.0	52.2	52.5	52.2
Other	4.6	4.9	5.2	5.5	5.7	5.9	6.0	6.4	7.3	8.0
Total	**503.9**	**528.0**	**534.7**	**542.8**	**547.6**	**557.9**	**564.7**	**578.4**	**605.0**	**629.2**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Atlantic High Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	32.1	33.4	34.5	35.6	36.7	38.0	38.7	42.3	45.3	47.2
Oil	48.0	49.0	48.6	49.2	48.8	48.2	48.3	45.6	44.6	45.2
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane	1.6	1.6	1.7	1.8	1.8	1.8	1.8	1.9	1.9	2.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	28.3	28.9	28.4	28.5	28.6	29.0	29.3	30.1	31.1	32.2
Other	1.5	1.4	1.4	1.4	1.3	1.4	1.4	1.4	1.3	1.8
Total	**111.5**	**114.3**	**114.6**	**116.4**	**117.2**	**118.4**	**119.4**	**121.2**	**124.2**	**128.4**
Commercial										
Electricity	20.1	20.6	21.5	22.5	23.4	24.4	25.5	28.2	32.2	35.9
Oil	31.8	33.1	32.4	31.8	31.4	31.0	30.4	30.0	30.3	30.6
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane	1.5	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.2	2.2
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.7	0.7
Total	**53.9**	**55.9**	**56.1**	**56.5**	**57.1**	**57.7**	**58.2**	**60.8**	**65.3**	**69.4**
Industrial										
Electricity	45.4	46.1	49.9	53.4	57.5	61.8	65.6	74.8	86.7	91.5
Oil	57.6	64.0	65.2	65.3	66.4	67.7	68.6	70.4	78.1	89.3
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, Coke and Coke Oven Gas	11.8	13.8	14.4	15.1	15.9	16.6	17.5	19.1	22.6	25.8
Steam	1.3	1.2	1.2	1.2	1.2	1.3	1.3	1.4	1.4	1.5
Wood Waste	49.4	50.1	50.8	51.5	52.3	52.4	52.6	53.0	53.8	54.0
Propane	0.8	0.9	0.9	1.0	1.0	1.0	1.1	1.2	1.3	1.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.8	0.1	0.3	0.4	0.6	0.7	0.7	1.0	1.5	1.7
Total	**167.2**	**176.2**	**182.7**	**187.9**	**194.9**	**201.6**	**207.5**	**220.8**	**245.5**	**265.0**
Non-Energy										
Asphalt	10.2	10.8	11.0	11.3	11.5	11.7	12.0	12.8	14.1	15.7
Lubes and Greases	2.1	2.2	2.5	2.6	2.7	2.8	2.9	3.1	3.2	3.4
Naphtha	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Petroleum Coke	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	2.7	4.0	1.2	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**15.3**	**17.3**	**15.0**	**15.8**	**16.2**	**16.5**	**16.8**	**17.8**	**19.3**	**21.2**
Transportation										
Motor Gasoline	93.8	96.1	95.6	95.6	96.1	96.7	97.2	99.2	103.0	107.1
Diesel Fuel Oil	38.5	42.1	45.2	48.2	50.8	53.0	55.0	60.2	67.3	74.4
Aviation Turbo-Total	16.5	17.7	18.1	18.3	18.4	18.4	18.5	18.7	18.6	19.6
Aviation Gasoline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Heavy Fuel Oil	6.3	7.5	7.7	7.8	7.6	7.6	7.5	7.1	6.6	6.3
Other	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.7	0.8
Total	**155.9**	**164.2**	**167.6**	**170.8**	**173.8**	**176.5**	**179.1**	**186.3**	**196.6**	**208.8**
Total End Use										
Electricity	97.6	100.1	105.9	111.5	117.6	124.2	129.8	145.2	164.1	174.6
Oil	308.2	327.3	328.3	332.5	336.0	339.5	342.7	349.5	368.2	394.2
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, Coke and Coke Oven Gas	11.8	15.3	15.9	16.6	17.3	18.1	19.0	20.5	23.9	27.1
Steam	1.4	1.4	1.3	1.4	1.4	1.4	1.5	1.5	1.6	1.6
Wood	28.3	28.9	28.4	28.5	28.6	29.0	29.3	30.1	31.1	32.2
Wood Waste	49.4	50.1	50.8	51.5	52.3	52.4	52.6	53.0	53.8	54.0
Other	327.2	4.9	5.2	5.5	5.8	6.1	6.3	6.9	8.2	9.1
Total	**503.9**	**528.0**	**535.9**	**547.5**	**559.1**	**570.8**	**581.2**	**606.9**	**651.0**	**692.8**

(Petajoules)	Quebec Low Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	155.3	161.4	170.5	176.5	179.1	184.4	189.7	203.4	219.5	231.8
Oil	86.1	76.8	69.8	65.3	64.2	61.8	59.1	51.3	41.2	33.6
Natural Gas	28.1	28.8	30.4	31.4	32.5	33.1	33.6	33.9	33.2	32.8
Propane	3.4	3.3	3.5	3.6	3.6	3.7	3.7	3.9	4.0	4.1
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	37.1	34.6	37.3	39.7	40.3	41.2	41.9	43.8	45.9	47.8
Other	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
Total	**310.5**	**305.3**	**311.9**	**317.0**	**320.2**	**324.7**	**328.7**	**336.8**	**344.5**	**350.8**
Commercial										
Electricity	88.8	92.5	92.6	92.3	94.0	95.6	97.2	100.4	105.4	109.0
Oil	28.6	25.7	24.8	25.9	25.7	25.9	26.1	25.6	24.4	22.6
Natural Gas	49.5	47.7	52.2	55.6	57.7	59.6	62.0	68.2	73.5	76.1
Propane	2.3	2.9	2.9	3.0	3.0	3.1	3.2	3.3	3.5	3.5
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.2	0.2	0.3	0.4	0.5	0.5	0.5	0.6	0.6	0.7
Total	**169.4**	**169.0**	**172.9**	**177.1**	**180.9**	**184.7**	**189.0**	**198.1**	**207.4**	**212.0**
Industrial										
Electricity	257.2	267.5	265.6	258.3	256.8	262.0	268.3	287.5	307.9	334.9
Oil	64.4	60.3	69.2	74.5	75.9	78.4	79.7	75.9	75.2	65.4
Natural Gas	108.7	121.9	124.8	130.0	135.8	143.0	149.9	164.9	179.7	188.7
Coal, Coke and Coke Oven Gas	22.5	23.4	23.6	23.5	23.4	23.9	24.3	24.7	24.6	24.0
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	69.8	70.9	71.7	72.6	73.5	73.6	73.7	74.0	74.7	74.3
Propane	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.4	2.3	2.3
Butanes	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other	0.0	0.4	0.9	1.3	1.8	2.1	2.5	3.5	5.4	5.7
Total	**525.1**	**547.0**	**558.4**	**562.8**	**569.7**	**585.6**	**601.0**	**633.3**	**670.2**	**695.6**
Non-Energy										
Asphalt	29.4	36.1	31.9	32.2	32.8	33.8	34.5	36.5	38.3	39.9
Lubes and Greases	5.4	6.2	6.6	7.1	7.6	8.0	8.3	9.1	9.7	10.0
Naphtha	1.2	1.3	1.4	1.5	1.6	1.7	1.9	2.2	2.6	2.7
Petroleum Coke	21.3	26.4	26.7	27.1	27.4	27.7	28.1	29.1	30.9	32.8
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	7.3	29.7	33.7	34.3	32.5	33.2	33.8	35.9	39.7	43.8
Propane	0.5	0.2	0.2	0.2	0.9	0.9	0.9	0.9	1.0	1.1
Butanes	3.9	1.4	1.4	1.5	2.8	2.9	2.9	3.1	3.5	3.8
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	1.1	8.2	8.6	9.0	9.4	9.8	10.2	11.6	14.4	17.9
Total	**70.0**	**109.5**	**110.4**	**112.9**	**115.0**	**118.0**	**120.6**	**128.4**	**140.0**	**151.9**
Transportation										
Motor Gasoline	235.9	237.5	235.5	234.5	234.9	238.0	241.5	254.2	267.6	275.4
Diesel Fuel Oil	70.2	72.9	76.9	80.7	83.6	86.6	89.5	97.1	104.9	112.5
Aviation Turbo-Total	30.5	34.2	36.0	36.7	37.1	37.3	37.4	37.6	38.6	39.4
Aviation Gasoline	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Heavy Fuel Oil	20.3	17.7	18.5	18.9	18.9	19.1	19.3	19.8	19.6	20.6
Other	2.7	3.1	3.4	3.6	3.9	4.2	4.5	5.4	6.9	8.7
Total	**360.4**	**366.2**	**371.0**	**375.1**	**379.1**	**386.0**	**392.9**	**414.9**	**438.3**	**457.4**
Total End Use										
Electricity	502.4	522.6	529.9	528.4	531.2	543.5	556.8	593.2	635.1	678.5
Oil	602.4	633.8	640.4	648.4	652.2	662.1	670.1	686.6	707.7	717.2
Natural Gas	186.7	199.0	208.1	217.9	227.0	236.8	246.8	268.7	288.8	300.5
Coal, Coke and Coke Oven Gas	22.5	23.4	23.6	23.5	23.4	23.9	24.3	24.7	24.6	24.0
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	37.1	34.6	37.3	39.7	40.3	41.2	41.9	43.8	45.9	47.8
Wood Waste	69.8	70.9	71.7	72.6	73.5	73.6	73.7	74.0	74.7	74.3
Other	14.4	12.8	13.7	14.5	17.3	17.9	18.6	20.5	23.6	25.3
Total	**1435.4**	**1496.9**	**1524.7**	**1544.9**	**1564.9**	**1598.9**	**1632.2**	**1711.6**	**1800.3**	**1867.6**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Quebec High Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	155.3	161.4	169.8	175.2	177.9	183.0	187.9	200.9	213.7	226.3
Oil	86.1	76.8	70.0	65.3	64.2	61.1	57.7	47.3	33.2	26.1
Natural Gas	28.1	28.8	29.7	30.8	32.3	33.0	33.5	34.4	35.1	32.7
Propane	3.4	3.3	3.5	3.5	3.6	3.6	3.7	3.8	3.9	4.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	37.1	34.6	37.1	39.4	40.1	40.8	41.4	42.9	44.2	45.9
Other	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
Total	**310.5**	**305.3**	**310.6**	**314.7**	**318.6**	**322.1**	**324.8**	**329.9**	**330.6**	**335.6**
Commercial										
Electricity	88.8	92.5	92.6	91.6	92.7	94.4	96.5	102.3	110.4	119.7
Oil	28.6	25.7	24.0	25.0	24.7	24.0	23.3	20.3	18.5	19.0
Natural Gas	49.5	47.7	52.6	56.7	60.0	62.6	64.9	71.1	73.6	71.9
Propane	2.3	2.9	2.9	3.0	3.0	3.1	3.2	3.3	3.5	3.7
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.2	0.2	0.3	0.4	0.5	0.5	0.5	0.7	1.0	1.1
Total	**169.4**	**169.0**	**172.4**	**176.7**	**180.9**	**184.5**	**188.5**	**197.6**	**207.0**	**215.4**
Industrial										
Electricity	257.2	267.5	266.2	265.1	272.6	277.8	287.8	310.8	349.9	399.8
Oil	64.4	60.3	64.7	68.0	69.3	69.7	70.5	63.3	66.0	70.2
Natural Gas	108.7	121.9	130.5	143.8	157.5	166.7	176.3	195.3	218.3	225.8
Coal, Coke and Coke Oven Gas	22.5	23.4	23.7	24.2	25.0	25.4	26.1	26.7	27.9	28.4
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	69.8	70.9	71.9	72.9	73.9	74.1	74.4	75.0	76.3	76.5
Propane	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.6	2.7
Butanes	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other	0.0	0.4	0.9	1.4	1.9	2.3	2.7	3.8	6.1	6.7
Total	**525.1**	**547.0**	**560.6**	**578.0**	**602.9**	**618.7**	**640.7**	**678.0**	**747.6**	**810.5**
Non-Energy										
Asphalt	29.4	36.1	31.7	32.5	33.1	33.7	34.7	36.6	39.8	43.5
Lubes and Greases	5.4	6.2	6.4	6.8	7.2	7.4	7.6	8.0	8.4	9.0
Naphtha	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.6	1.8
Petroleum Coke	21.3	26.4	26.7	27.1	27.4	27.7	28.1	29.1	30.9	32.8
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	7.3	29.7	33.7	34.3	32.5	33.2	33.8	35.9	39.7	43.8
Propane	0.5	0.2	0.2	0.2	0.9	0.9	0.9	0.9	1.0	1.1
Butanes	3.9	1.4	1.4	1.5	2.8	2.9	2.9	3.1	3.5	3.8
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	1.1	8.2	8.6	9.0	9.4	9.8	10.2	11.6	14.4	17.9
Total	**70.0**	**109.5**	**110.0**	**112.7**	**114.7**	**117.0**	**119.6**	**126.8**	**139.3**	**153.6**
Transportation										
Motor Gasoline	235.9	237.5	234.6	233.5	233.9	236.3	239.2	249.9	263.2	272.4
Diesel Fuel Oil	70.2	72.9	76.5	79.8	82.7	85.6	88.6	96.4	106.8	117.4
Aviation Turbo-Total	30.5	34.2	35.4	36.2	36.8	37.2	37.7	39.1	40.6	42.9
Aviation Gasoline	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Heavy Fuel Oil	20.3	17.7	18.3	18.5	18.3	18.4	18.5	18.5	18.7	20.0
Other	2.7	3.1	3.5	3.9	4.3	4.7	5.2	6.4	8.5	11.0
Total	**360.4**	**366.2**	**369.1**	**372.7**	**376.8**	**383.1**	**389.9**	**411.1**	**438.6**	**464.4**
Total End Use										
Electricity	502.4	522.6	529.9	533.2	544.7	556.8	574.0	616.0	676.5	748.8
Oil	602.4	633.8	632.7	638.2	641.7	646.4	652.1	658.3	682.5	717.4
Natural Gas	186.7	199.0	213.6	232.3	250.9	263.5	276.3	302.9	330.0	334.4
Coal, Coke and Coke Oven Gas	22.5	23.4	23.7	24.2	25.0	25.4	26.1	26.7	27.9	28.4
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	37.1	34.6	37.1	39.4	40.1	40.8	41.4	42.9	44.2	45.9
Wood Waste	69.8	70.9	71.9	72.9	73.9	74.1	74.4	75.0	76.3	76.5
Other	14.4	12.8	13.8	14.7	17.7	18.4	19.2	21.5	25.6	28.1
Total	**1435.4**	**1496.9**	**1522.6**	**1554.9**	**1593.9**	**1625.5**	**1663.5**	**1743.4**	**1863.1**	**1979.5**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Ontario Low Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	140.4	144.9	151.9	154.1	156.8	161.5	164.1	169.4	170.1	176.2
Oil	75.7	66.9	61.5	57.8	55.5	52.0	50.4	52.3	50.6	45.6
Natural Gas	237.5	232.6	245.3	247.8	251.2	257.0	264.0	273.5	289.1	295.1
Propane	11.7	11.4	11.9	11.9	11.9	12.2	12.4	12.8	13.2	13.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	24.6	24.2	24.7	24.6	24.6	25.2	25.8	27.2	33.0	33.6
Other	0.7	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8
Total	**490.6**	**480.6**	**496.0**	**496.9**	**500.9**	**508.7**	**517.5**	**536.1**	**556.8**	**564.7**
Commercial										
Electricity	124.8	128.6	133.0	134.1	136.7	138.3	140.9	145.3	150.5	159.8
Oil	21.3	19.8	19.0	18.6	18.1	18.0	17.9	17.2	17.2	14.6
Natural Gas	169.4	165.8	171.7	174.3	178.2	183.5	189.4	200.3	212.8	225.2
Propane	2.5	2.6	2.6	2.7	2.7	2.7	2.7	2.6	2.5	2.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	1.0	1.1	1.3	1.4	1.5	1.6	1.6	1.8	1.9	2.1
Total	**319.0**	**317.9**	**327.6**	**331.1**	**337.3**	**344.1**	**352.5**	**367.2**	**384.9**	**404.0**
Industrial										
Electricity	160.7	165.9	167.6	169.8	168.5	177.7	187.0	204.3	224.0	240.9
Oil	72.8	78.5	80.2	82.1	81.6	85.9	89.7	93.4	89.2	78.3
Natural Gas	300.8	294.7	296.2	296.0	290.9	304.7	319.2	347.6	386.3	424.7
Coal, Coke and Coke Oven Gas	189.5	204.6	211.7	216.5	218.5	230.1	240.8	252.9	284.4	317.7
Steam	30.2	28.7	27.2	25.5	23.4	22.7	21.8	19.7	23.4	27.2
Wood Waste	71.1	71.8	72.2	72.8	73.4	73.5	73.6	74.0	74.5	74.1
Propane	3.2	3.2	3.2	3.2	3.1	3.2	3.4	3.5	3.6	3.7
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Other	0.0	0.6	1.3	1.9	2.6	2.8	3.0	3.6	4.6	7.1
Total	**828.3**	**848.0**	**859.7**	**867.9**	**862.1**	**900.7**	**938.6**	**999.1**	**1090.2**	**1173.8**
Non-Energy										
Asphalt	34.9	38.3	37.8	38.3	38.4	39.4	40.5	42.2	45.3	48.5
Lubes and Greases	19.2	19.2	20.8	21.7	22.5	23.5	24.7	27.0	30.2	32.4
Naphtha	7.3	6.8	8.1	8.7	9.2	9.7	10.3	11.5	12.9	13.3
Petroleum Coke	9.6	9.2	9.3	9.4	9.5	9.6	9.7	10.1	10.7	11.4
Natural Gas	29.4	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2
Oil	107.7	101.0	118.3	120.5	122.8	125.0	127.2	134.4	147.3	161.5
Propane	7.9	13.2	21.5	21.7	22.0	22.3	22.4	23.3	24.7	26.5
Butanes	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	4.7	6.7	6.8	6.9	7.0	7.1	7.3	7.7	8.4	9.0
Other Oil	7.3	4.5	4.5	4.5	4.6	4.6	4.7	4.8	5.1	5.3
Total	**228.3**	**224.1**	**252.3**	**256.9**	**261.2**	**266.5**	**272.0**	**286.2**	**309.8**	**333.0**
Transportation										
Motor Gasoline	415.9	424.2	428.8	433.2	438.7	448.1	457.6	484.2	509.5	527.9
Diesel Fuel Oil	115.5	122.1	128.4	134.9	139.9	145.4	150.2	161.7	173.9	185.5
Aviation Turbo-Total	51.1	53.5	56.3	57.4	58.1	58.4	58.6	59.0	60.8	62.0
Aviation Gasoline	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Heavy Fuel Oil	10.1	9.5	9.5	9.2	8.7	8.7	8.7	8.4	7.6	7.0
Other	8.9	9.6	10.1	10.6	11.1	11.6	12.0	13.5	15.9	18.8
Total	**603.0**	**620.4**	**634.7**	**646.8**	**658.1**	**673.6**	**688.5**	**728.3**	**769.1**	**802.5**
Total End Use										
Electricity	427.2	440.7	454.0	459.6	463.9	479.5	494.1	521.6	547.9	580.9
Oil	950.0	954.9	984.1	997.8	1009.2	1029.8	1051.5	1107.7	1161.7	1194.6
Natural Gas	737.3	718.8	739.1	744.3	746.7	771.8	799.5	848.9	916.6	974.4
Coal, Coke and Coke Oven Gas	189.5	204.6	211.7	216.5	218.5	230.1	240.8	252.9	284.4	317.7
Steam	30.2	28.9	27.3	25.7	23.6	22.9	22.0	19.9	23.6	27.4
Wood	24.6	24.2	24.7	24.6	24.6	25.2	25.8	27.2	33.0	33.6
Wood Waste	71.1	71.8	72.2	72.8	73.4	73.5	73.6	74.0	74.5	74.1
Other	39.3	47.1	57.0	58.2	59.6	60.7	61.7	64.7	69.1	75.4
Total	**2469.2**	**2491.0**	**2570.3**	**2599.7**	**2619.5**	**2693.6**	**2769.1**	**2916.9**	**3110.9**	**3278.1**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Ontario High Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	140.4	144.9	151.1	153.3	156.2	161.0	164.5	165.3	164.9	174.7
Oil	75.7	66.9	61.8	58.2	55.7	50.4	46.8	41.9	34.5	28.6
Natural Gas	237.5	232.6	242.7	245.3	249.4	256.1	261.7	277.0	290.1	295.4
Propane	11.7	11.4	11.8	11.8	11.9	12.1	12.3	12.5	12.7	13.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	24.6	24.2	24.6	24.5	24.5	25.1	25.6	26.6	31.8	32.5
Other	0.7	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8
Total	**490.6**	**480.6**	**492.6**	**493.8**	**498.5**	**505.5**	**511.7**	**524.1**	**534.7**	**545.0**
Commercial										
Electricity	124.8	128.6	132.6	133.3	136.1	137.9	140.8	140.9	144.8	160.8
Oil	21.3	19.8	18.6	17.8	16.6	15.8	15.3	13.5	12.0	12.6
Natural Gas	169.4	165.8	171.9	176.2	182.8	189.1	195.4	207.9	218.7	229.6
Propane	2.5	2.6	2.6	2.7	2.7	2.7	2.7	2.5	2.4	2.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	1.0	1.1	1.3	1.4	1.5	1.6	1.7	1.9	2.6	2.8
Total	**319.0**	**317.9**	**327.0**	**331.4**	**339.8**	**347.2**	**355.8**	**366.7**	**380.5**	**408.2**
Industrial										
Electricity	160.7	165.9	168.1	175.4	183.0	194.7	209.8	227.1	255.8	285.6
Oil	72.8	78.5	75.0	74.6	75.0	77.2	81.0	78.8	73.9	75.6
Natural Gas	300.8	294.7	304.0	319.0	331.8	352.1	376.7	410.8	469.5	519.6
Coal, Coke and Coke Oven Gas	189.5	204.6	212.7	222.9	233.8	244.8	258.6	279.8	329.8	374.0
Steam	30.2	28.7	27.3	26.5	25.5	24.9	24.4	21.9	26.8	32.2
Wood Waste	71.1	71.8	72.5	73.1	73.8	74.1	74.3	75.0	76.1	76.3
Propane	3.2	3.2	3.2	3.3	3.4	3.6	3.8	3.9	4.2	4.4
Butanes	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Other	0.0	0.6	1.3	2.0	2.8	3.1	3.4	4.0	5.3	8.4
Total	**828.3**	**848.0**	**864.2**	**896.9**	**929.1**	**974.5**	**1032.1**	**1101.4**	**1241.4**	**1376.2**
Non-Energy										
Asphalt	34.9	38.3	37.5	38.4	39.2	40.4	41.7	44.0	48.8	54.4
Lubes and Greases	19.2	19.2	20.4	20.9	21.4	22.2	23.1	24.7	27.6	30.7
Naphtha	7.3	6.8	7.8	8.0	8.1	8.4	8.7	9.3	10.3	11.4
Petroleum Coke	9.6	9.2	9.3	9.4	9.5	9.6	9.7	10.1	10.7	11.4
Natural Gas	29.4	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2
Oil	107.7	101.0	118.3	120.5	122.8	125.0	127.2	134.4	147.3	161.5
Propane	7.9	13.2	21.5	21.7	22.0	22.3	22.4	23.3	24.7	26.5
Butanes	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	4.7	6.7	6.8	6.9	7.0	7.1	7.3	7.7	8.4	9.0
Other Oil	7.3	4.5	4.5	4.5	4.6	4.6	4.7	4.8	5.1	5.3
Total	**228.3**	**224.1**	**251.3**	**255.5**	**259.9**	**264.8**	**270.0**	**283.5**	**308.1**	**335.3**
Transportation										
Motor Gasoline	415.9	424.2	427.3	431.8	437.8	446.8	456.0	481.9	513.0	539.4
Diesel Fuel Oil	115.5	122.1	127.7	133.3	138.8	144.3	149.5	162.4	180.8	198.9
Aviation Turbo-Total	51.1	53.5	55.4	56.7	57.6	58.3	59.2	61.4	63.9	67.5
Aviation Gasoline	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Heavy Fuel Oil	10.1	9.5	9.4	9.0	8.5	8.4	8.3	7.9	7.3	6.8
Other	8.9	9.6	10.5	11.3	12.1	12.9	13.7	16.2	20.3	24.1
Total	**603.0**	**620.4**	**631.7**	**643.6**	**656.3**	**672.1**	**688.2**	**731.2**	**786.8**	**838.1**
Total End Use										
Electricity	427.2	440.7	453.3	463.7	477.2	495.8	517.3	536.0	569.2	625.5
Oil	950.0	954.9	974.5	984.6	997.1	1012.8	1032.6	1076.5	1136.6	1205.4
Natural Gas	737.3	718.8	744.7	766.8	790.6	824.2	861.0	923.8	1007.8	1075.4
Coal, Coke and Coke Oven Gas	189.5	204.6	212.7	222.9	233.8	244.8	258.6	279.8	329.8	374.0
Steam	30.2	28.9	27.5	26.7	25.7	25.1	24.6	22.0	26.9	32.4
Wood	24.6	24.2	24.6	24.5	24.5	25.1	25.6	26.6	31.8	32.5
Wood Waste	71.1	71.8	72.5	73.1	73.8	74.1	74.3	75.0	76.1	76.3
Other	39.3	47.1	57.2	58.8	60.8	62.2	63.7	67.2	73.5	81.2
Total	**2469.2**	**2491.0**	**2566.8**	**2621.3**	**2683.6**	**2764.1**	**2857.8**	**3007.0**	**3251.6**	**3502.7**

(Petajoules)	Manitoba Low Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	21.7	22.4	24.3	24.6	24.8	25.1	25.3	25.6	26.9	27.7
Oil	8.1	8.3	8.4	8.4	8.3	8.2	8.3	8.4	7.7	7.7
Natural Gas	24.9	21.3	24.0	24.2	24.5	25.0	25.2	26.0	27.9	28.6
Propane	1.4	1.2	1.3	1.3	1.2	1.2	1.2	1.1	1.1	1.2
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.7	2.4	2.5	2.4	2.2	2.3	2.3	2.3	2.2	2.1
Other	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Total	**59.2**	**55.9**	**60.8**	**61.2**	**61.4**	**62.1**	**62.6**	**63.8**	**66.2**	**67.7**
Commercial										
Electricity	12.6	13.0	13.3	13.4	13.7	13.9	14.0	14.4	14.9	15.3
Oil	2.1	2.1	2.1	1.9	1.8	1.8	1.8	1.8	1.6	1.4
Natural Gas	26.3	22.5	25.9	26.2	26.9	27.5	28.1	29.5	30.7	32.2
Propane	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.9	0.8	0.8	0.7	0.6	0.4	0.3	0.3	0.2	0.1
Total	**42.3**	**38.7**	**42.4**	**42.6**	**43.4**	**44.0**	**44.7**	**46.3**	**47.7**	**49.3**
Industrial										
Electricity	14.5	14.9	15.4	15.5	15.4	15.8	16.2	17.9	20.2	25.7
Oil	6.4	6.4	6.6	6.7	6.7	6.8	6.9	7.2	7.1	7.1
Natural Gas	17.2	14.7	15.3	15.9	16.1	16.8	17.3	19.2	21.5	26.5
Coal, Coke and Coke Oven Gas	2.2	2.1	2.1	2.2	2.2	2.2	2.3	2.4	2.6	3.1
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	12.2	12.5	12.7	13.0	13.3	13.3	13.3	13.3	13.4	13.3
Propane	1.0	0.9	1.0	1.0	0.9	0.9	1.0	1.0	1.0	1.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.6
Total	**53.4**	**51.5**	**53.2**	**54.4**	**54.7**	**56.0**	**57.2**	**61.3**	**66.1**	**77.3**
Non-Energy										
Asphalt	2.1	2.8	2.9	2.9	2.9	3.0	3.0	3.1	3.3	3.7
Lubes and Greases	1.3	1.4	1.4	1.5	1.6	1.7	1.7	1.9	2.0	2.1
Naphtha	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Petroleum Coke	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Total	**8.5**	**9.6**	**9.7**	**9.8**	**9.9**	**10.0**	**10.1**	**10.4**	**10.8**	**11.3**
Transportation										
Motor Gasoline	50.2	49.8	48.5	47.4	46.6	46.0	45.6	45.3	46.1	48.5
Diesel Fuel Oil	21.4	23.0	24.0	25.3	26.1	27.1	27.9	30.3	33.0	35.6
Aviation Turbo - Total	6.5	6.6	6.9	6.9	7.0	7.0	7.0	6.9	7.0	7.1
Aviation Gasoline	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.2	1.5
Total	**79.5**	**80.9**	**80.9**	**81.2**	**81.2**	**81.7**	**82.2**	**84.2**	**88.0**	**93.3**
Total End Use										
Electricity	48.8	50.3	53.1	53.5	53.8	54.8	55.6	58.0	61.9	68.9
Oil	99.0	101.5	101.8	102.3	102.1	102.8	103.5	106.1	109.1	114.5
Natural Gas	73.2	63.3	70.1	71.2	72.5	74.2	75.6	79.8	85.2	92.4
Coal, Coke and Coke Oven Gas	2.7	2.5	2.6	2.6	2.5	2.6	2.6	2.7	2.8	3.2
Steam	0.4	0.4	0.3	0.3	0.2	0.0	0.0	0.0	0.0	0.0
Wood	2.7	2.4	2.5	2.4	2.2	2.3	2.3	2.3	2.2	2.1
Wood Waste	12.2	12.5	12.7	13.0	13.3	13.3	13.3	13.3	13.4	13.3
Other	3.9	3.7	3.9	3.9	3.9	3.9	3.9	3.9	4.1	4.6
Total	**242.9**	**236.6**	**247.0**	**249.1**	**250.6**	**253.8**	**256.7**	**266.0**	**278.8**	**299.0**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Manitoba High Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	21.7	22.4	24.3	24.9	25.0	25.3	25.4	25.8	26.1	26.5
Oil	8.1	8.3	8.4	8.5	8.3	8.1	8.0	7.6	7.3	7.5
Natural Gas	24.9	21.3	23.8	24.1	24.6	25.2	25.7	27.2	28.0	27.4
Propane	1.4	1.2	1.3	1.3	1.2	1.2	1.2	1.1	1.1	1.1
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.7	2.4	2.5	2.4	2.2	2.3	2.3	2.3	2.2	2.0
Other	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**59.2**	**55.9**	**60.7**	**61.5**	**61.8**	**62.4**	**62.9**	**64.3**	**65.0**	**64.8**
Commercial										
Electricity	12.6	13.0	13.3	13.3	13.6	13.8	14.0	14.4	15.3	16.5
Oil	2.1	2.1	2.1	2.0	1.8	1.7	1.6	1.4	1.4	1.5
Natural Gas	26.3	22.5	25.9	26.4	27.3	28.1	28.8	30.0	31.5	32.8
Propane	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.9	0.8	0.8	0.7	0.6	0.4	0.3	0.3	0.2	0.2
Total	**42.3**	**38.7**	**42.4**	**42.7**	**43.7**	**44.4**	**45.2**	**46.5**	**48.7**	**51.3**
Industrial										
Electricity	14.5	14.9	15.6	15.7	15.8	15.9	16.6	18.8	22.7	28.8
Oil	6.4	6.4	6.3	6.2	6.1	6.1	6.3	6.5	6.7	7.7
Natural Gas	17.2	14.7	15.9	17.2	18.1	18.7	19.9	22.8	25.9	29.3
Coal, Coke and Coke Oven Gas	2.2	2.1	2.2	2.2	2.3	2.3	2.4	2.7	3.0	3.5
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	12.2	12.5	12.8	13.0	13.3	13.4	13.4	13.5	13.7	13.7
Propane	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.2
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.6
Total	**53.4**	**51.5**	**53.7**	**55.5**	**56.8**	**57.5**	**59.8**	**65.7**	**73.6**	**84.9**
Non-Energy										
Asphalt	2.1	2.8	2.9	2.9	2.9	3.0	3.0	3.2	3.5	3.9
Lubes and Greases	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8
Naphtha	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Petroleum Coke	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Total	**8.5**	**9.6**	**9.6**	**9.7**	**9.8**	**9.9**	**10.0**	**10.2**	**10.7**	**11.2**
Transportation										
Motor Gasoline	50.2	49.8	48.4	47.2	46.3	45.6	45.1	44.4	45.2	47.3
Diesel Fuel Oil	21.4	23.0	23.8	24.9	25.8	26.7	27.6	30.0	33.3	36.7
Aviation Turbo - Total	6.5	6.6	6.8	6.9	6.9	7.0	7.0	7.2	7.3	7.7
Aviation Gasoline	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.8	0.8	0.9	0.9	1.0	1.0	1.1	1.3	1.5	1.9
Total	**79.5**	**80.9**	**80.6**	**80.6**	**80.8**	**81.1**	**81.6**	**83.6**	**88.1**	**94.4**
Total End Use										
Electricity	48.8	50.3	53.2	53.9	54.4	55.0	56.1	59.0	64.1	71.8
Oil	99.0	101.5	101.2	101.1	100.9	100.9	101.4	103.2	107.7	115.5
Natural Gas	73.2	63.3	70.5	72.6	75.0	77.1	79.3	85.0	90.5	94.9
Coal, Coke and Coke Oven Gas	2.7	2.5	2.6	2.6	2.7	2.7	2.7	2.9	3.2	3.6
Steam	0.4	0.4	0.3	0.3	0.2	0.0	0.0	0.0	0.0	0.0
Wood	2.7	2.4	2.5	2.4	2.2	2.3	2.3	2.3	2.2	2.0
Wood Waste	12.2	12.5	12.8	13.0	13.3	13.4	13.4	13.5	13.7	13.7
Other	3.9	3.7	3.9	4.0	4.0	4.1	4.1	4.2	4.5	5.1
Total	**242.9**	**236.6**	**247.0**	**250.0**	**252.9**	**255.3**	**259.4**	**270.3**	**286.0**	**306.6**

(Petajoules)	Saskatchewan Low Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	14.0	14.7	16.2	16.3	16.0	16.1	16.3	16.6	18.1	19.0
Oil	21.1	20.4	20.9	20.2	20.2	20.1	20.2	21.1	22.1	22.8
Natural Gas	37.4	34.4	37.7	39.3	39.5	40.0	40.4	41.7	42.9	46.8
Propane	1.7	1.6	1.5	1.4	1.2	1.2	1.2	1.3	1.3	1.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.2	1.7	2.0	1.9	1.7	1.7	1.8	1.8	1.8	1.8
Other	1.2	1.1	0.9	0.7	0.5	0.5	0.5	0.5	0.5	0.5
Total	**77.6**	**73.8**	**79.2**	**79.8**	**79.2**	**79.8**	**80.4**	**83.1**	**86.8**	**92.3**
Commercial										
Electricity	10.0	10.5	10.6	10.5	10.5	10.4	10.5	10.7	11.3	11.8
Oil	1.8	1.7	1.7	1.6	1.6	1.6	1.6	1.5	1.5	1.5
Natural Gas	23.5	22.5	24.1	24.9	25.3	25.8	26.4	28.0	29.4	31.1
Propane	1.0	0.9	1.0	1.0	1.1	1.1	1.1	1.1	1.2	1.3
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**36.3**	**35.6**	**37.4**	**38.1**	**38.5**	**38.9**	**39.5**	**41.4**	**43.4**	**45.7**
Industrial										
Electricity	11.3	11.9	13.0	12.8	12.7	13.2	13.6	15.5	18.4	21.5
Oil	12.0	11.9	12.4	12.0	11.8	12.1	12.3	13.3	14.4	15.1
Natural Gas	33.5	33.4	34.9	33.8	33.0	33.8	34.5	38.5	44.9	51.9
Coal, Coke and Coke Oven Gas	3.7	3.6	3.8	3.6	3.5	3.5	3.5	3.7	3.9	4.0
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	3.5	3.5	3.5	3.5	3.5	3.6	3.6	3.7	3.9	3.9
Propane	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	0.9
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.6
Total	**65.1**	**65.3**	**68.7**	**67.0**	**65.8**	**67.4**	**68.7**	**76.1**	**86.9**	**98.0**
Non-Energy										
Asphalt	5.7	7.1	7.3	7.1	7.0	7.1	7.3	8.2	8.9	10.1
Lubes and Greases	1.9	1.8	2.1	2.1	2.2	2.3	2.4	2.5	2.7	2.8
Naphtha	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Petroleum Coke	2.1	2.3	2.3	2.4	2.4	2.5	2.5	2.7	3.0	3.3
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Total	**10.2**	**11.4**	**11.9**	**11.8**	**11.8**	**12.0**	**12.4**	**13.6**	**14.7**	**16.5**
Transportation										
Motor Gasoline	64.9	64.0	61.0	58.6	56.8	55.6	54.6	53.2	54.7	59.4
Diesel Fuel Oil	20.3	20.6	20.9	21.3	21.5	21.8	21.9	22.4	23.1	25.0
Aviation Turbo - Total	2.9	2.9	3.0	2.9	2.9	2.8	2.7	2.6	2.3	2.3
Aviation Gasoline	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.1	1.4
Total	**89.3**	**88.7**	**86.1**	**84.1**	**82.5**	**81.4**	**80.5**	**79.5**	**81.6**	**88.4**
Total End Use										
Electricity	35.3	37.0	39.8	39.6	39.3	39.8	40.4	42.9	47.8	52.4
Oil	133.6	133.2	132.1	129.0	126.9	126.2	126.0	128.1	133.2	143.0
Natural Gas	94.4	90.3	96.7	98.1	97.8	99.8	101.3	108.3	117.4	129.9
Coal, Coke and Coke Oven Gas	4.6	4.5	4.3	4.0	3.7	3.7	3.7	3.9	4.1	4.2
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.2	1.7	2.0	1.9	1.7	1.7	1.8	1.8	1.8	1.8
Wood Waste	3.5	3.5	3.5	3.5	3.5	3.6	3.6	3.7	3.9	3.9
Other	4.9	4.8	4.9	4.8	4.7	4.7	4.7	4.9	5.2	5.8
Total	**278.5**	**274.9**	**283.4**	**280.9**	**277.7**	**279.5**	**281.5**	**293.6**	**313.3**	**340.9**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Saskatchewan High Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	14.0	14.7	16.4	16.3	16.3	16.5	16.6	17.1	19.3	20.5
Oil	21.1	20.4	20.6	20.3	20.1	19.8	19.7	20.0	21.2	23.5
Natural Gas	37.4	34.4	38.2	39.0	40.2	41.1	41.6	44.1	47.3	48.8
Propane	1.7	1.6	1.5	1.4	1.2	1.3	1.3	1.3	1.4	1.5
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.2	1.7	2.0	1.9	1.8	1.8	1.8	1.9	1.9	1.9
Other	1.2	1.1	0.9	0.7	0.5	0.5	0.5	0.5	0.6	0.6
Total	**77.6**	**73.8**	**79.5**	**79.6**	**80.2**	**80.9**	**81.5**	**84.9**	**91.7**	**96.6**
Commercial										
Electricity	10.0	10.5	10.7	10.7	10.7	10.8	10.8	11.3	12.2	13.4
Oil	1.8	1.7	1.7	1.7	1.6	1.5	1.5	1.5	1.6	1.6
Natural Gas	23.5	22.5	24.0	24.7	25.3	26.0	26.5	28.3	30.4	32.8
Propane	1.0	0.9	1.0	1.0	1.1	1.1	1.1	1.2	1.3	1.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**36.3**	**35.6**	**37.4**	**38.1**	**38.8**	**39.4**	**40.0**	**42.3**	**45.4**	**49.2**
Industrial										
Electricity	11.3	11.9	13.1	13.7	14.1	14.7	15.4	18.1	22.3	25.8
Oil	12.0	11.9	12.0	11.7	11.3	11.0	11.0	11.3	12.2	14.0
Natural Gas	33.5	33.4	35.8	37.9	39.7	41.6	43.2	50.2	59.2	64.4
Coal, Coke and Coke Oven Gas	3.7	3.6	3.8	3.9	3.9	4.0	4.1	4.4	4.7	4.8
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	3.5	3.5	3.5	3.5	3.6	3.6	3.7	3.8	4.0	4.0
Propane	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.1
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.7
Total	**65.1**	**65.3**	**69.5**	**71.9**	**73.9**	**76.3**	**78.6**	**89.3**	**104.0**	**114.7**
Non-Energy										
Asphalt	5.7	7.1	7.4	7.7	7.8	7.7	7.9	8.8	10.7	11.8
Lubes and Greases	1.9	1.8	2.0	2.1	2.1	2.2	2.2	2.3	2.4	2.6
Naphtha	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Petroleum Coke	2.1	2.3	2.3	2.4	2.4	2.5	2.5	2.7	3.0	3.3
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Total	**10.2**	**11.4**	**11.9**	**12.3**	**12.5**	**12.5**	**12.8**	**13.9**	**16.3**	**17.9**
Transportation										
Motor Gasoline	64.9	64.0	61.1	58.8	57.1	55.9	54.9	53.7	56.1	61.0
Diesel Fuel Oil	20.3	20.6	20.8	21.2	21.5	21.8	22.1	22.7	24.1	26.6
Aviation Turbo - Total	2.9	2.9	2.9	2.9	2.8	2.8	2.8	2.7	2.4	2.5
Aviation Gasoline	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.8	0.9	0.9	1.0	1.0	1.1	1.1	1.2	1.4	1.8
Total	**89.3**	**88.7**	**86.1**	**84.2**	**82.8**	**81.9**	**81.2**	**80.6**	**84.4**	**92.3**
Total End Use										
Electricity	35.3	37.0	40.2	40.7	41.2	42.0	42.8	46.5	53.8	59.7
Oil	133.6	133.2	131.4	129.2	127.2	125.7	125.2	126.1	134.2	147.5
Natural Gas	94.4	90.3	97.9	101.5	105.3	108.7	111.4	122.7	137.1	146.2
Coal, Coke and Coke Oven Gas	4.6	4.5	4.4	4.3	4.1	4.2	4.3	4.6	4.9	4.9
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.2	1.7	2.0	1.9	1.8	1.8	1.8	1.9	1.9	1.9
Wood Waste	3.5	3.5	3.5	3.5	3.6	3.6	3.7	3.8	4.0	4.0
Other	4.9	4.8	4.9	4.9	4.9	5.0	5.1	5.4	5.9	6.6
Total	**278.5**	**274.9**	**284.4**	**286.1**	**288.1**	**291.0**	**294.2**	**311.0**	**341.9**	**370.8**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Alberta Low Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	24.3	25.5	26.3	25.7	25.9	26.2	26.5	28.1	28.7	29.0
Oil	19.5	19.6	20.5	20.8	21.2	21.0	21.0	21.6	22.3	23.2
Natural Gas	132.1	121.8	135.3	135.1	134.9	134.6	134.6	136.8	143.3	150.5
Propane	9.7	9.2	9.6	9.3	9.0	8.9	8.9	8.9	8.7	9.1
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.6	2.3	2.4	2.3	2.2	2.2	2.2	2.3	2.4	2.5
Other	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4	1.4
Total	**189.6**	**179.8**	**195.6**	**194.8**	**194.8**	**194.4**	**194.7**	**199.3**	**206.8**	**215.6**
Commercial										
Electricity	34.0	35.8	36.3	36.2	35.9	35.6	35.8	37.1	40.5	44.0
Oil	3.8	3.5	3.4	3.3	3.2	3.1	3.1	3.2	3.2	3.2
Natural Gas	83.3	76.6	79.9	80.8	80.9	81.1	81.9	85.6	91.2	96.0
Propane	4.7	4.6	4.8	4.8	4.8	4.8	4.8	5.0	4.6	4.7
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**125.8**	**120.6**	**124.4**	**125.1**	**124.7**	**124.6**	**125.7**	**130.9**	**139.5**	**148.0**
Industrial										
Electricity	53.8	56.7	56.2	57.4	55.9	55.2	55.7	59.9	72.3	86.6
Oil	44.7	45.0	44.4	43.6	41.0	40.4	40.0	40.5	43.6	47.3
Natural Gas	265.1	246.9	251.2	268.6	278.6	278.2	280.4	294.4	329.8	383.6
Coal, Coke and Coke Oven Gas	0.1	0.1	0.1	0.1	0.1	5.3	6.3	9.8	12.6	16.3
Steam	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Wood Waste	16.6	16.9	17.2	17.5	17.8	17.9	18.1	18.4	19.1	19.0
Propane	3.1	3.0	3.0	2.9	2.7	2.7	2.6	2.6	2.7	2.8
Butanes	1.2	1.2	1.2	1.1	1.1	1.0	1.0	1.0	1.1	1.1
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**384.7**	**369.9**	**373.4**	**391.5**	**397.4**	**400.9**	**404.2**	**426.7**	**481.4**	**557.0**
Non-Energy										
Asphalt	29.4	26.0	25.7	24.6	23.7	23.5	23.3	24.8	28.9	32.3
Lubes and Greases	4.2	4.5	4.6	4.7	4.9	5.0	5.1	5.3	5.7	5.9
Naphtha	0.7	0.6	0.7	0.7	0.7	0.8	0.8	0.9	0.9	1.0
Petroleum Coke	2.4	2.5	2.6	2.6	2.7	2.8	2.9	3.2	3.8	4.5
Natural Gas	100.3	111.9	111.9	111.9	118.3	118.3	118.3	126.1	133.9	133.9
Oil	8.3	15.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Propane	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	3.0	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Ethane	78.9	78.9	78.9	86.8	86.8	86.8	86.8	130.7	130.7	130.7
Other Oil	0.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Total	**227.7**	**244.1**	**240.0**	**247.2**	**252.9**	**252.9**	**253.0**	**306.8**	**319.7**	**324.1**
Transportation										
Motor Gasoline	149.8	152.9	146.3	140.3	135.3	131.0	127.4	121.0	122.2	128.2
Diesel Fuel Oil	64.1	65.1	64.7	64.8	64.1	63.9	63.6	62.8	61.7	63.8
Aviation Turbo - Total	25.0	24.1	25.2	25.5	25.6	25.6	25.5	25.3	25.3	25.8
Aviation Gasoline	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	4.1	4.4	4.6	4.7	4.9	5.0	5.2	5.6	6.4	7.6
Total	**243.6**	**247.2**	**241.4**	**235.9**	**230.5**	**226.1**	**222.2**	**215.3**	**216.3**	**226.0**
Total End Use										
Electricity	112.2	118.3	119.0	119.5	118.0	117.3	118.3	125.4	141.8	160.0
Oil	352.8	361.0	351.2	344.2	335.6	330.2	325.9	321.7	330.9	348.4
Natural Gas	580.8	557.3	578.6	596.8	613.2	612.7	615.9	644.0	699.9	766.2
Coal, Coke and Coke Oven Gas	1.4	1.4	1.5	1.5	1.5	6.7	7.7	11.2	13.9	17.5
Steam	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Wood	2.6	2.3	2.4	2.3	2.2	2.2	2.2	2.3	2.4	2.5
Wood Waste	16.6	16.9	17.2	17.5	17.8	17.9	18.1	18.4	19.1	19.0
Other	104.9	104.2	104.8	112.3	111.8	111.7	111.6	155.8	155.5	156.7
Total	**1171.4**	**1161.6**	**1174.9**	**1194.4**	**1200.2**	**1199.0**	**1199.8**	**1278.9**	**1363.8**	**1470.5**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	Alberta High Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	24.3	25.5	25.9	25.7	26.0	26.5	26.9	29.1	31.8	32.0
Oil	19.5	19.6	20.1	20.5	21.1	20.9	20.9	21.6	22.8	24.4
Natural Gas	132.1	121.8	136.1	135.9	136.0	137.2	138.0	143.0	151.1	152.2
Propane	9.7	9.2	9.6	9.3	9.1	9.1	9.1	9.3	9.3	9.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.6	2.3	2.5	2.3	2.2	2.3	2.3	2.4	2.5	2.5
Other	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.5	1.4
Total	**189.6**	**179.8**	**195.6**	**195.3**	**195.9**	**197.4**	**198.8**	**207.0**	**219.0**	**221.8**
Commercial										
Electricity	34.0	35.8	36.7	37.5	38.3	39.2	40.4	43.6	49.8	53.3
Oil	3.8	3.5	3.5	3.4	3.4	3.4	3.5	3.5	3.6	3.6
Natural Gas	83.3	76.6	80.7	83.4	85.9	88.1	89.5	94.0	100.2	104.0
Propane	4.7	4.6	4.8	4.9	5.1	5.2	5.3	5.6	5.3	5.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**125.8**	**120.6**	**125.6**	**129.2**	**132.7**	**136.0**	**138.6**	**146.8**	**158.9**	**166.3**
Industrial										
Electricity	53.8	56.7	61.0	62.5	64.9	67.2	71.4	83.1	105.2	120.3
Oil	44.7	45.0	46.4	46.8	47.9	49.7	51.6	56.6	64.0	66.6
Natural Gas	265.1	246.9	268.5	296.2	338.9	358.2	371.2	475.3	477.4	496.1
Coal, Coke and Coke Oven Gas	0.1	0.1	0.1	0.1	0.1	6.5	8.1	50.0	141.1	180.0
Steam	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3
Wood Waste	16.6	16.9	17.3	17.6	17.9	18.1	18.2	18.6	19.6	19.6
Propane	3.1	3.0	3.1	3.1	3.2	3.3	3.4	3.6	4.0	4.0
Butanes	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.4	1.6	1.5
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**384.7**	**369.9**	**397.8**	**427.8**	**474.4**	**504.4**	**525.4**	**688.8**	**813.0**	**888.4**
Non-Energy										
Asphalt	29.4	26.0	28.0	27.4	28.4	30.0	30.3	34.5	41.1	39.8
Lubes and Greases	4.2	4.5	4.5	4.6	4.8	4.9	5.0	5.2	5.5	5.8
Naphtha	0.7	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.9	0.9
Petroleum Coke	2.4	2.5	2.6	2.6	2.7	2.8	2.9	3.2	3.8	4.5
Natural Gas	100.3	111.9	111.9	111.9	118.3	118.3	118.3	126.1	133.9	133.9
Oil	8.3	15.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Propane	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	3.0	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Ethane	78.9	78.9	78.9	86.8	86.8	86.8	86.8	130.7	130.7	130.7
Other Oil	0.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Total	**227.7**	**244.1**	**242.3**	**249.8**	**257.4**	**259.3**	**259.8**	**316.2**	**331.6**	**331.4**
Transportation										
Motor Gasoline	149.8	152.9	146.8	141.9	138.0	135.2	133.0	130.6	135.7	139.8
Diesel Fuel Oil	64.1	65.1	64.9	65.0	65.0	65.1	65.3	65.9	67.3	71.5
Aviation Turbo - Total	25.0	24.1	24.8	25.2	25.4	25.5	25.8	26.3	26.6	28.1
Aviation Gasoline	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	4.1	4.4	4.7	5.0	5.3	5.6	6.0	6.9	8.4	10.0
Total	**243.6**	**247.2**	**241.9**	**237.7**	**234.3**	**232.1**	**230.6**	**230.2**	**238.6**	**249.9**
Total End Use										
Electricity	112.2	118.3	123.9	126.0	129.5	133.2	139.0	156.2	187.2	206.1
Oil	352.8	361.0	355.5	351.3	350.4	351.4	352.1	361.3	384.4	398.1
Natural Gas	580.8	557.3	597.4	627.8	679.8	702.6	717.9	839.8	864.8	889.2
Coal, Coke and Coke Oven Gas	1.4	1.4	1.5	1.5	1.5	7.9	9.6	51.4	142.5	181.2
Steam	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3
Wood	2.6	2.3	2.5	2.3	2.2	2.3	2.3	2.4	2.5	2.5
Wood Waste	16.6	16.9	17.3	17.6	17.9	18.1	18.2	18.6	19.6	19.6
Other	104.9	104.2	105.1	113.0	113.1	113.6	114.0	159.2	160.0	160.8
Total	**1171.4**	**1161.6**	**1203.3**	**1239.7**	**1294.7**	**1329.2**	**1353.2**	**1589.1**	**1761.1**	**1857.7**

(Petajoules)	British Columbia and Territories									
	Low Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	40.2	40.7	43.1	43.2	43.4	44.1	44.6	45.3	45.6	49.3
Oil	15.3	15.1	15.1	14.3	13.6	13.2	12.8	12.3	11.2	10.3
Natural Gas	64.8	67.7	70.9	70.4	71.0	72.3	74.4	77.4	82.6	86.8
Propane	2.8	2.7	2.9	2.8	2.8	2.8	2.8	2.9	3.0	3.2
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	11.5	11.0	12.4	12.4	12.4	13.0	12.9	13.4	13.7	15.3
Other	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7
Total	**135.1**	**137.6**	**145.0**	**143.7**	**143.7**	**146.0**	**148.2**	**151.9**	**156.7**	**165.6**
Commercial										
Electricity	35.6	36.0	36.2	36.4	36.9	37.2	37.6	38.5	41.3	43.9
Oil	14.4	14.6	14.3	14.1	13.8	13.9	13.9	14.2	14.4	14.4
Natural Gas	33.8	35.3	35.7	36.2	37.7	38.8	39.8	41.7	42.7	45.0
Propane	2.3	2.2	2.1	2.1	2.1	2.1	2.2	2.1	2.2	2.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.3	0.3	0.4
Total	**86.1**	**88.1**	**88.4**	**88.8**	**90.8**	**92.3**	**93.7**	**96.8**	**101.1**	**106.0**
Industrial										
Electricity	89.7	90.7	91.4	90.7	89.7	91.4	92.9	98.1	111.0	127.7
Oil	54.9	59.7	59.3	55.6	51.4	50.3	48.8	45.9	45.6	43.4
Natural Gas	70.6	73.8	72.5	73.5	74.0	80.1	83.5	95.2	117.7	133.9
Coal, Coke and Coke Oven Gas	6.0	7.0	7.7	8.3	8.8	9.8	10.7	13.6	14.2	14.3
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	187.0	193.1	197.8	200.5	204.2	206.6	209.0	213.5	220.9	228.4
Propane	2.4	2.5	2.4	2.3	2.2	2.2	2.2	2.2	2.2	2.1
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.1	0.2	0.3	0.4	0.5	0.6	1.0	1.8	2.0
Total	**410.6**	**427.0**	**431.4**	**431.2**	**430.7**	**441.0**	**447.9**	**469.6**	**513.6**	**551.8**
Non-Energy										
Asphalt	11.0	12.4	12.1	11.9	11.8	12.0	12.2	12.7	14.3	16.2
Lubes and Greases	3.8	4.1	4.3	4.6	4.8	5.0	5.2	5.5	5.9	6.2
Naphtha	0.6	0.7	0.6	0.7	0.7	0.7	0.8	0.9	1.0	1.0
Petroleum Coke	4.6	4.4	4.6	4.7	4.9	5.1	5.2	5.7	6.7	7.9
Natural Gas	14.1	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Oil	0.9	1.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	2.6	6.9	7.0	7.1	7.2	7.3	7.4	7.8	8.5	9.2
Total	**37.6**	**47.1**	**46.3**	**46.7**	**47.1**	**47.8**	**48.5**	**50.3**	**54.0**	**58.2**
Transportation										
Motor Gasoline	128.2	126.3	124.7	122.9	121.3	120.0	119.0	117.7	119.0	124.5
Diesel Fuel Oil	52.9	58.1	60.3	62.5	64.1	65.4	66.5	69.7	73.2	78.4
Aviation Turbo - Total	24.4	28.1	29.5	30.0	30.2	30.2	30.3	30.2	30.8	31.3
Aviation Gasoline	1.4	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Heavy Fuel Oil	5.0	5.4	6.0	6.4	6.8	6.9	6.9	7.0	6.8	7.0
Other	3.9	4.3	4.5	4.7	4.9	5.1	5.3	5.9	7.0	8.2
Total	**215.8**	**223.9**	**226.6**	**228.1**	**228.9**	**229.3**	**229.7**	**232.2**	**238.3**	**251.2**
Total End Use										
Electricity	165.8	167.7	170.9	170.6	170.2	173.0	175.4	182.3	198.4	221.3
Oil	319.8	338.8	339.8	336.6	332.4	331.9	331.0	331.6	339.1	351.8
Natural Gas	184.0	195.0	197.5	198.7	201.4	210.0	216.7	233.8	263.3	286.8
Coal, Coke and Coke Oven Gas	6.3	7.2	7.9	8.5	9.0	10.0	10.9	13.8	14.4	14.5
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	11.5	11.0	12.4	12.4	12.4	13.0	12.9	13.4	13.7	15.3
Wood Waste	187.0	193.1	197.8	200.5	204.2	206.6	209.0	213.5	220.9	228.4
Other	10.9	10.9	11.2	11.2	11.4	11.7	11.9	12.5	13.8	14.6
Total	**885.2**	**923.7**	**937.7**	**938.5**	**941.2**	**956.3**	**967.9**	**1000.8**	**1063.5**	**1132.8**

Table A4-6 (Continued)
End Use Demand by Fuel and Sector - Canada and Regions

(Petajoules)	British Columbia and Territories									
	High Case									
	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Residential										
Electricity	40.2	40.7	43.0	43.2	43.2	44.1	43.9	44.0	43.8	45.0
Oil	15.3	15.1	14.8	14.3	13.7	12.3	11.9	9.9	8.7	8.6
Natural Gas	64.8	67.7	70.9	70.1	70.4	72.1	74.4	78.2	82.4	84.3
Propane	2.8	2.7	2.9	2.8	2.8	2.8	2.8	2.8	2.9	3.0
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	11.5	11.0	12.4	12.4	12.4	13.0	12.7	13.1	13.2	14.3
Other	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total	**135.1**	**137.6**	**144.6**	**143.3**	**143.0**	**144.8**	**146.4**	**148.6**	**151.6**	**155.8**
Commercial										
Electricity	35.6	36.0	36.2	36.4	36.8	37.1	37.5	38.8	42.4	45.7
Oil	14.4	14.6	14.1	13.8	13.7	13.4	13.0	12.4	11.9	12.5
Natural Gas	33.8	35.3	35.8	36.2	37.6	38.9	40.1	42.5	44.5	47.4
Propane	2.3	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.3	2.4
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.2	0.2	0.3	0.4	0.6	0.6
Total	**86.1**	**88.1**	**88.2**	**88.5**	**90.5**	**91.8**	**93.0**	**96.2**	**101.6**	**108.7**
Industrial										
Electricity	89.7	90.7	90.8	91.0	91.3	92.9	95.4	102.7	119.0	141.3
Oil	54.9	59.7	56.7	52.0	48.1	47.7	47.2	45.2	48.0	48.8
Natural Gas	70.6	73.8	74.5	80.1	87.7	97.8	104.0	116.1	134.8	151.7
Coal, Coke and Coke Oven Gas	6.0	7.0	7.7	8.4	9.3	10.5	11.6	14.9	15.7	16.1
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	187.0	193.1	197.2	200.8	205.5	208.0	210.5	215.3	223.4	231.4
Propane	2.4	2.5	2.4	2.4	2.3	2.4	2.4	2.4	2.4	2.3
Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.1	0.2	0.3	0.4	0.6	0.7	1.1	2.0	2.3
Total	**410.6**	**427.0**	**429.5**	**435.0**	**444.8**	**459.9**	**472.0**	**497.9**	**545.2**	**594.0**
Non-Energy										
Asphalt	11.0	12.4	12.1	11.9	11.9	12.1	12.4	13.0	14.2	16.8
Lubes and Greases	3.8	4.1	4.2	4.4	4.5	4.6	4.7	4.9	5.1	5.5
Naphtha	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.8
Petroleum Coke	4.6	4.4	4.6	4.7	4.9	5.1	5.2	5.7	6.7	7.9
Natural Gas	14.1	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Oil	0.9	1.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Propane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	2.6	6.9	7.0	7.1	7.2	7.3	7.4	7.8	8.5	9.2
Total	**37.6**	**47.1**	**46.1**	**46.4**	**46.9**	**47.5**	**48.1**	**49.7**	**52.9**	**57.9**
Transportation										
Motor Gasoline	128.2	126.3	124.2	122.2	120.3	118.5	117.1	114.3	114.0	118.0
Diesel Fuel Oil	52.9	58.1	59.9	61.5	63.0	64.0	64.9	67.3	71.5	78.8
Aviation Turbo - Total	24.4	28.1	29.0	29.6	29.9	30.2	30.6	31.5	32.3	34.1
Aviation Gasoline	1.4	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Heavy Fuel Oil	5.0	5.4	5.9	6.3	6.6	6.6	6.6	6.5	6.4	6.8
Other	3.9	4.3	4.6	5.0	5.4	5.8	6.1	7.3	9.1	10.8
Total	**215.8**	**223.9**	**225.3**	**226.3**	**226.8**	**226.7**	**226.9**	**228.4**	**235.1**	**250.1**
Total End Use										
Electricity	165.8	167.7	170.2	170.8	171.6	174.4	177.2	185.8	205.5	232.6
Oil	319.8	338.8	335.0	330.3	326.4	324.4	323.6	321.1	330.0	349.7
Natural Gas	184.0	195.0	199.6	205.0	214.6	228.0	237.9	256.8	282.8	305.7
Coal, Coke and Coke Oven Gas	6.3	7.2	7.9	8.7	9.5	10.7	11.8	15.1	15.9	16.3
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	11.5	11.0	12.4	12.4	12.4	13.0	12.7	13.1	13.2	14.3
Wood Waste	187.0	193.1	197.2	200.8	205.5	208.0	210.5	215.3	223.4	231.4
Other	10.9	10.9	11.3	11.4	11.8	12.2	12.6	13.6	15.5	16.5
Total	**885.2**	**923.7**	**933.7**	**939.5**	**951.9**	**970.7**	**986.3**	**1020.9**	**1086.5**	**1166.4**

Table A4-7
End Use Demand by Fuel - Atlantic Provinces

(Petajoules)

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Newfoundland										
Low Case										
Electricity	32.9	33.7	33.9	34.5	35.2	36.2	37.1	38.7	42.3	44.7
Oil Products	78.1	82.3	81.7	81.0	80.7	80.7	81.0	81.1	84.4	89.6
Total	**134.0**	**139.3**	**138.7**	**138.5**	**139.0**	**140.2**	**141.8**	**143.7**	**152.3**	**161.7**
High Case										
Electricity	32.9	33.7	36.1	38.4	41.6	44.2	47.5	57.1	67.7	71.0
Oil Products	78.1	82.3	85.2	86.7	89.7	91.1	94.2	103.4	114.4	122.2
Total	**134.0**	**139.3**	**145.7**	**150.4**	**157.9**	**162.6**	**170.4**	**192.7**	**218.6**	**231.3**
Prince Edward Island										
Low Case										
Electricity	1.9	2.0	2.1	2.1	2.2	2.2	2.3	2.5	2.7	2.8
Oil Products	14.5	15.2	15.3	15.6	15.7	15.8	16.1	16.4	17.0	17.5
Total	**19.0**	**19.9**	**20.0**	**20.4**	**20.6**	**20.8**	**21.2**	**21.8**	**22.8**	**23.5**
High Case										
Electricity	1.9	2.0	2.1	2.1	2.2	2.2	2.3	2.4	2.7	2.8
Oil Products	14.5	15.2	15.0	15.2	15.2	15.2	15.3	15.1	15.4	16.1
Total	**19.0**	**19.9**	**19.7**	**20.0**	**20.1**	**20.2**	**20.3**	**20.4**	**20.9**	**22.0**
Nova Scotia										
Low Case										
Electricity	24.9	25.6	26.7	27.8	28.6	29.7	30.4	32.4	35.1	36.1
Oil Products	124.0	130.8	131.9	133.6	134.0	135.5	136.3	139.4	145.3	148.9
Total	**184.1**	**192.3**	**195.3**	**198.7**	**200.1**	**203.3**	**205.0**	**211.3**	**221.9**	**227.1**
High Case										
Electricity	24.9	25.6	26.5	27.7	28.7	30.0	30.7	33.3	36.8	39.3
Oil Products	124.0	130.8	130.0	131.1	131.3	131.9	131.7	131.0	135.8	144.1
Total	**184.1**	**192.3**	**192.5**	**195.2**	**196.5**	**198.8**	**199.4**	**201.6**	**211.9**	**224.5**
New Brunswick										
Low Case										
Electricity	37.9	38.9	41.6	43.6	44.9	47.4	48.7	51.4	54.6	56.9
Oil Products	91.7	98.9	99.8	101.5	102.2	104.6	105.8	107.4	110.1	115.8
Total	**166.8**	**176.4**	**180.7**	**185.3**	**187.9**	**193.6**	**196.7**	**201.5**	**208.0**	**217.0**
High Case										
Electricity	37.9	38.9	41.2	43.3	45.2	47.8	49.3	52.4	56.9	61.5
Oil Products	91.7	98.9	98.1	99.5	99.9	101.4	101.6	100.0	102.5	111.8
Total	**166.8**	**176.4**	**177.9**	**182.0**	**184.6**	**189.3**	**191.1**	**192.1**	**199.6**	**215.1**

Table A4-8
Total Petroleum Product Demand - Canada and Regions

(Petajoules)

Canada

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	5.6	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Motor Gasoline	1112.2	1119.0	1110.8	1102.0	1099.3	1105.6	1113.4	1145.1	1189.8	1236.7
Av. Turbo - Kerosene (Jet A-1)	120.0	140.7	148.7	152.1	154.2	155.2	156.0	158.0	164.2	167.4
- Naphtha (Jet B)	36.9	26.3	26.6	26.0	25.1	24.4	23.7	21.5	18.2	18.6
-Total	156.9	167.1	175.4	178.0	179.3	179.7	179.8	179.6	182.5	186.0
Light Fuel and Kerosene	302.0	272.4	257.6	247.6	239.4	232.5	227.4	217.5	203.1	185.3
Diesel Fuel Oil	587.5	617.0	637.1	654.6	666.2	684.2	698.3	735.3	775.8	820.0
Heavy Fuel Oil	277.4	311.0	307.1	304.7	311.0	338.7	348.3	344.5	371.3	354.3
Asphalt	122.7	133.4	128.7	128.2	127.7	130.2	132.4	139.2	151.7	164.6
Lubes and Greases	37.9	39.6	42.4	44.7	46.7	48.6	50.6	54.7	59.8	63.3
Petrochemical Feedstock	129.1	151.8	165.3	168.6	169.1	171.9	174.8	184.1	200.8	219.1
Refinery LPG	65.3	67.2	69.0	69.3	69.6	70.3	71.0	73.1	76.3	79.0
Other Products	252.9	285.8	288.8	290.6	291.5	296.3	300.4	311.8	332.0	350.0
Total Products [a]	**3049.6**	**3170.3**	**3188.2**	**3194.2**	**3205.5**	**3263.9**	**3302.2**	**3390.9**	**3548.9**	**3664.1**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	5.6	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Motor Gasoline	1112.2	1119.0	1107.9	1100.2	1098.9	1104.8	1112.8	1143.9	1199.3	1253.3
Av. Turbo - Kerosene (Jet A-1)	120.0	140.7	146.3	150.2	152.9	155.0	157.6	164.5	172.7	182.2
- Naphtha (Jet B)	36.9	26.3	26.2	25.7	24.9	24.4	24.0	22.4	19.2	20.2
-Total	156.9	167.1	172.4	175.8	177.8	179.4	181.6	186.9	191.8	202.5
Light Fuel and Kerosene	302.0	272.4	256.7	247.0	238.3	225.6	215.9	188.7	160.7	148.7
Diesel Fuel Oil	587.5	617.0	635.6	654.5	673.8	694.1	712.3	756.2	819.7	887.5
Heavy Fuel Oil	277.4	311.0	296.4	292.8	305.0	339.9	351.3	353.0	376.7	345.9
Asphalt	122.7	133.4	130.6	132.0	134.9	138.7	142.0	152.8	172.3	185.9
Lubes and Greases	37.9	39.6	41.6	43.1	44.4	45.8	47.2	49.9	54.0	59.0
Petrochemical Feedstock	129.1	151.8	165.3	168.6	169.1	171.9	174.8	184.1	200.8	219.1
Refinery LPG	65.3	67.2	68.8	69.2	69.9	70.7	71.6	74.0	78.5	82.8
Other Products	252.9	285.8	288.6	290.9	294.9	301.1	306.5	319.6	343.7	364.4
Total Products [a]	**3049.6**	**3170.3**	**3169.7**	**3180.1**	**3213.0**	**3277.9**	**3321.9**	**3415.0**	**3603.4**	**3755.0**

Note: [a] Fuels used to generate electricity exports are not included.

Table A4-8 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Petajoules)

Atlantic

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Motor Gasoline	93.9	96.0	95.9	95.9	96.2	96.9	97.5	99.3	101.2	104.1
Av. Turbo - Kerosene (Jet A-1)	9.3	11.4	12.0	12.3	12.5	12.6	12.6	12.8	13.3	13.6
- Naphtha (Jet B)	7.3	6.3	6.4	6.3	6.0	5.9	5.7	5.2	4.4	4.5
-Total	16.5	17.7	18.5	18.6	18.5	18.5	18.3	18.0	17.7	18.0
Light Fuel and Kerosene	69.7	69.5	69.5	69.7	68.7	68.6	68.8	67.9	68.7	70.2
Diesel Fuel Oil	57.5	61.3	65.4	68.9	71.7	74.4	76.6	81.9	88.3	94.2
Heavy Fuel Oil	90.9	132.6	114.2	105.7	111.5	133.3	140.0	135.5	156.8	159.3
Asphalt	10.2	10.8	11.0	11.1	11.2	11.5	11.6	11.9	12.7	13.9
Lubes and Greases	2.1	2.3	2.5	2.7	2.9	3.0	3.2	3.4	3.6	3.7
Petrochemical Feedstock	2.7	4.0	1.2	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Refinery LPG	7.9	7.9	8.3	8.5	8.6	8.8	8.9	9.2	9.7	10.0
Other Products	18.7	20.0	19.1	18.9	19.3	20.6	21.1	21.2	22.8	23.5
Total Products [a]	**370.5**	**422.6**	**406.0**	**402.0**	**410.6**	**437.6**	**447.9**	**450.2**	**483.5**	**498.9**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Motor Gasoline	93.9	96.0	95.6	95.7	96.1	96.7	97.3	99.3	103.1	107.2
Av. Turbo - Kerosene (Jet A-1)	9.3	11.4	11.8	12.2	12.4	12.6	12.8	13.3	14.0	14.8
- Naphtha (Jet B)	7.3	6.3	6.3	6.2	6.0	5.9	5.8	5.4	4.6	4.9
-Total	16.5	17.7	18.1	18.3	18.4	18.4	18.5	18.7	18.6	19.6
Light Fuel and Kerosene	69.7	69.5	69.1	69.1	68.3	67.4	66.9	63.7	63.1	64.2
Diesel Fuel Oil	57.5	61.3	65.4	69.1	72.5	75.4	77.8	84.4	94.0	103.2
Heavy Fuel Oil	90.9	132.6	117.3	116.8	132.3	167.3	178.5	187.3	201.7	163.3
Asphalt	10.2	10.8	11.0	11.3	11.5	11.7	12.0	12.8	14.1	15.7
Lubes and Greases	2.1	2.3	2.5	2.6	2.8	2.9	2.9	3.1	3.2	3.4
Petrochemical Feedstock	2.7	4.0	1.2	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Refinery LPG	7.9	7.9	8.3	8.5	8.8	9.0	9.2	9.8	10.6	11.1
Other Products	18.7	20.0	19.2	19.4	20.3	22.2	22.9	23.7	25.1	24.1
Total Products [a]	**370.5**	**422.6**	**408.3**	**412.8**	**433.0**	**473.1**	**488.1**	**504.7**	**535.4**	**513.9**

Note: [a] Fuels used to generate electricity exports are not included.

Table A4-8 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Petajoules)

Quebec

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Motor Gasoline	234.8	236.6	234.5	233.5	233.9	237.0	240.5	253.2	266.5	274.3
Av. Turbo - Kerosene (Jet A-1)	27.7	31.5	33.3	34.1	34.5	34.8	35.0	35.4	36.8	37.5
- Naphtha (Jet B)	2.8	2.7	2.7	2.6	2.5	2.5	2.4	2.2	1.9	1.9
-Total	30.5	34.2	36.0	36.7	37.1	37.3	37.4	37.6	38.6	39.4
Light Fuel and Kerosene	102.5	89.5	81.7	77.9	76.6	74.4	71.7	63.0	51.5	41.9
Diesel Fuel Oil	98.0	103.0	108.2	112.1	115.2	121.0	124.3	132.9	141.0	148.5
Heavy Fuel Oil	79.5	65.2	74.4	80.4	82.0	84.6	85.8	86.4	97.1	88.6
Asphalt	29.4	36.1	31.9	32.2	32.8	33.8	34.5	36.5	38.3	39.9
Lubes and Greases	5.4	6.2	6.6	7.1	7.6	8.0	8.3	9.1	9.7	10.0
Petrochemical Feedstock	7.3	29.7	33.7	34.4	32.6	33.2	33.9	35.9	39.7	43.8
Refinery LPG	10.0	10.3	10.5	10.6	10.8	11.0	11.1	11.5	12.0	12.2
Other Products	56.6	71.3	72.5	73.7	74.7	76.3	77.6	81.4	87.9	93.6
Total Products [a]	**654.9**	**682.9**	**690.7**	**699.4**	**703.9**	**717.2**	**725.8**	**748.1**	**783.2**	**793.0**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Motor Gasoline	234.8	236.6	233.6	232.5	232.9	235.3	238.2	248.8	262.1	271.3
Av. Turbo - Kerosene (Jet A-1)	27.7	31.5	32.8	33.6	34.3	34.7	35.3	36.9	38.7	40.8
- Naphtha (Jet B)	2.8	2.7	2.7	2.6	2.5	2.5	2.4	2.3	1.9	2.1
-Total	30.5	34.2	35.4	36.2	36.8	37.2	37.7	39.1	40.6	42.9
Light Fuel and Kerosene	102.5	89.5	81.1	77.3	76.0	72.4	68.6	56.0	39.6	31.9
Diesel Fuel Oil	98.0	103.0	107.7	111.8	115.6	121.3	124.9	133.8	145.8	157.7
Heavy Fuel Oil	79.5	65.2	69.6	72.6	73.0	72.9	72.7	72.7	86.6	85.8
Asphalt	29.4	36.1	31.7	32.5	33.1	33.7	34.7	36.6	39.8	43.5
Lubes and Greases	5.4	6.2	6.4	6.9	7.2	7.4	7.7	8.1	8.4	9.0
Petrochemical Feedstock	7.3	29.7	33.7	34.4	32.6	33.2	33.9	35.9	39.7	43.8
Refinery LPG	10.0	10.3	10.4	10.5	10.6	10.8	10.9	11.1	11.8	12.3
Other Products	56.6	71.3	72.1	73.1	74.2	75.3	76.5	79.8	86.4	93.3
Total Products [a]	**654.9**	**682.9**	**682.4**	**688.5**	**692.6**	**700.4**	**706.5**	**722.7**	**761.6**	**792.1**

Note: [a] Fuels used to generate electricity exports are not included.

(Petajoules)

Ontario

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Motor Gasoline	410.5	415.0	419.4	423.7	429.1	438.3	447.6	473.7	498.7	517.2
Av. Turbo - Kerosene (Jet A-1)	44.7	50.1	52.9	54.1	54.9	55.3	55.5	56.2	58.5	59.6
- Naphtha (Jet B)	6.4	3.4	3.4	3.3	3.2	3.1	3.0	2.8	2.3	2.4
-Total	51.1	53.5	56.3	57.4	58.1	58.4	58.6	59.0	60.8	62.0
Light Fuel and Kerosene	91.1	78.0	71.8	67.7	64.4	60.8	59.0	60.1	58.1	50.2
Diesel Fuel Oil	153.3	161.9	168.0	174.2	178.9	185.3	191.0	203.5	215.2	225.5
Heavy Fuel Oil	66.8	69.8	73.3	76.0	77.0	81.6	84.6	88.1	85.9	79.0
Asphalt	34.9	38.3	37.8	38.3	38.4	39.4	40.5	42.2	45.3	48.5
Lubes and Greases	19.2	19.3	20.9	21.8	22.6	23.6	24.8	27.1	30.4	32.6
Petrochemical Feedstock	109.5	101.4	118.7	120.9	123.2	125.4	127.6	134.8	147.8	162.0
Refinery LPG	25.8	26.5	28.2	28.5	28.9	29.5	30.0	31.5	33.1	34.3
Other Products	87.9	91.5	95.0	96.8	98.2	100.6	103.1	109.1	115.6	119.7
Total Products [a]	**1051.6**	**1056.6**	**1090.9**	**1106.8**	**1120.3**	**1144.4**	**1168.3**	**1230.5**	**1292.3**	**1332.2**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Motor Gasoline	410.5	415.0	417.9	422.3	428.2	436.9	446.1	471.4	502.3	528.6
Av. Turbo - Kerosene (Jet A-1)	44.7	50.1	52.1	53.5	54.4	55.2	56.1	58.6	61.5	64.9
- Naphtha (Jet B)	6.4	3.4	3.3	3.3	3.2	3.1	3.1	2.9	2.5	2.6
-Total	51.1	53.5	55.4	56.7	57.6	58.3	59.2	61.4	63.9	67.5
Light Fuel and Kerosene	91.1	78.0	71.9	67.7	63.6	57.7	53.7	47.0	38.2	32.3
Diesel Fuel Oil	153.3	161.9	167.2	173.5	180.0	186.7	193.6	207.1	226.1	244.3
Heavy Fuel Oil	66.8	69.8	67.7	66.6	66.6	68.6	70.4	67.6	63.5	71.6
Asphalt	34.9	38.3	37.5	38.4	39.2	40.4	41.7	44.0	48.8	54.4
Lubes and Greases	19.2	19.3	20.5	21.0	21.5	22.3	23.2	24.8	27.7	30.8
Petrochemical Feedstock	109.5	101.4	118.7	120.9	123.2	125.4	127.6	134.8	147.8	162.0
Refinery LPG	25.8	26.5	28.0	28.3	28.7	29.2	29.7	31.0	32.8	35.0
Other Products	87.9	91.5	94.1	95.3	96.8	98.6	100.9	105.3	112.2	120.0
Total Products [a]	**1051.6**	**1056.6**	**1080.2**	**1092.2**	**1106.9**	**1125.5**	**1147.6**	**1196.0**	**1264.7**	**1347.9**

Note: [a] Fuels used to generate electricity exports are not included.

Table A4-8 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Petajoules)

Manitoba

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Motor Gasoline	50.2	49.8	48.5	47.4	46.6	46.0	45.6	45.3	46.1	48.5
Av. Turbo - Kerosene (Jet A-1)	4.4	5.1	5.4	5.5	5.6	5.7	5.7	5.8	6.0	6.1
- Naphtha (Jet B)	2.1	1.4	1.5	1.4	1.4	1.3	1.3	1.2	1.0	1.0
-Total	6.5	6.6	6.9	6.9	7.0	7.0	7.0	6.9	7.0	7.1
Light Fuel and Kerosene	4.1	3.8	3.7	3.6	3.4	3.2	3.1	2.6	1.7	1.5
Diesel Fuel Oil	32.6	34.6	35.4	36.8	37.6	38.7	39.7	42.9	45.5	48.5
Heavy Fuel Oil	2.2	2.0	2.3	2.4	2.4	2.4	2.5	2.7	2.6	2.3
Asphalt	2.1	2.8	2.9	2.9	2.9	3.0	3.0	3.1	3.3	3.7
Lubes and Greases	1.3	1.4	1.4	1.5	1.6	1.7	1.7	1.9	2.0	2.1
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refinery LPG	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other Products	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.7
Total Products [a]	**100.3**	**102.5**	**102.7**	**103.1**	**103.0**	**103.5**	**104.2**	**106.9**	**109.9**	**115.3**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Motor Gasoline	50.2	49.8	48.4	47.2	46.3	45.7	45.1	44.4	45.3	47.3
Av. Turbo - Kerosene (Jet A-1)	4.4	5.1	5.3	5.5	5.6	5.6	5.7	6.0	6.3	6.6
- Naphtha (Jet B)	2.1	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.0	1.1
-Total	6.5	6.6	6.8	6.9	6.9	7.0	7.0	7.2	7.3	7.7
Light Fuel and Kerosene	4.1	3.8	3.9	3.8	3.5	3.0	2.7	1.6	1.2	1.2
Diesel Fuel Oil	32.6	34.6	35.2	36.4	37.4	38.4	39.5	42.8	46.3	50.3
Heavy Fuel Oil	2.2	2.0	2.0	1.8	1.7	1.5	1.6	1.6	1.6	2.3
Asphalt	2.1	2.8	2.9	2.9	2.9	3.0	3.0	3.2	3.5	3.9
Lubes and Greases	1.3	1.4	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refinery LPG	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other Products	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6
Total Products [a]	**100.3**	**102.5**	**102.0**	**102.0**	**101.8**	**101.6**	**102.2**	**104.0**	**108.5**	**116.3**

Note: [a] Fuels used to generate electricity exports are not included.

Table A4-8 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Petajoules)

Saskatchewan

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Motor Gasoline	64.9	64.0	61.0	58.6	56.8	55.6	54.6	53.2	54.7	59.4
Av. Turbo - Kerosene (Jet A-1)	0.8	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
- Naphtha (Jet B)	2.1	2.3	2.3	2.3	2.2	2.2	2.1	1.9	1.6	1.6
-Total	2.9	2.9	3.0	2.9	2.9	2.8	2.7	2.6	2.3	2.3
Light Fuel and Kerosene	6.9	5.6	5.7	4.7	4.4	4.3	4.1	4.1	3.6	2.7
Diesel Fuel Oil	45.2	46.0	46.8	47.2	47.3	47.7	48.2	50.2	52.9	56.8
Heavy Fuel Oil	3.8	3.7	3.7	3.7	3.8	4.0	4.1	4.6	5.0	5.4
Asphalt	5.7	7.1	7.3	7.1	7.0	7.1	7.3	8.2	8.9	10.1
Lubes and Greases	1.9	1.8	2.1	2.1	2.2	2.3	2.4	2.5	2.7	2.8
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refinery LPG	2.1	2.1	2.0	2.0	2.0	1.9	1.9	2.0	2.1	2.2
Other Products	7.1	7.6	7.6	7.5	7.5	7.5	7.6	7.9	8.4	9.1
Total Products [a]	**140.8**	**141.2**	**139.6**	**136.3**	**134.3**	**133.5**	**133.2**	**135.5**	**140.9**	**151.2**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Motor Gasoline [a]	64.9	64.0	61.1	58.8	57.1	55.9	54.9	53.7	56.1	61.0
Av. Turbo - Kerosene (Jet A-1)	0.8	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8
- Naphtha (Jet B)	2.1	2.3	2.3	2.3	2.2	2.1	2.1	2.0	1.7	1.8
-Total	2.9	2.9	2.9	2.9	2.8	2.8	2.8	2.7	2.4	2.5
Light Fuel and Kerosene	6.9	5.6	5.8	5.2	4.6	4.2	3.9	3.2	2.7	2.7
Diesel Fuel Oil	45.2	46.0	46.5	47.4	48.1	48.6	49.3	51.9	56.0	61.0
Heavy Fuel Oil	3.8	3.7	3.2	2.6	2.2	1.8	1.5	0.9	0.9	2.4
Asphalt	5.7	7.1	7.4	7.7	7.8	7.7	7.9	8.8	10.7	11.8
Lubes and Greases	1.9	1.8	2.0	2.1	2.1	2.2	2.2	2.3	2.4	2.6
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refinery LPG	2.1	2.1	2.0	2.0	2.0	1.9	1.9	2.0	2.1	2.3
Other Products	7.1	7.6	7.6	7.5	7.5	7.5	7.6	7.8	8.4	9.3
Total Products [a]	**140.8**	**141.2**	**138.9**	**136.5**	**134.6**	**133.0**	**132.4**	**133.4**	**142.0**	**156.0**

Note: [a] Fuels used to generate electricity exports are not included.

Table A4-8 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Petajoules)

Alberta

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Motor Gasoline	129.5	132.9	128.4	121.3	116.7	113.2	110.0	104.2	104.9	110.1
Av. Turbo - Kerosene (Jet A-1)	16.5	18.2	19.2	19.6	19.9	20.1	20.2	20.4	21.2	21.6
- Naphtha (Jet B)	8.5	5.9	6.0	5.8	5.6	5.5	5.3	4.8	4.1	4.2
-Total	25.0	24.1	25.2	25.5	25.6	25.6	25.5	25.3	25.3	25.8
Light Fuel and Kerosene	4.3	3.6	3.8	3.8	3.6	3.4	3.4	3.6	3.9	4.4
Diesel Fuel Oil	106.5	108.2	110.0	110.2	108.7	108.0	107.5	107.4	108.6	113.4
Heavy Fuel Oil	1.9	2.0	1.8	1.5	1.4	1.3	1.2	1.2	1.3	1.4
Asphalt	29.4	26.0	25.7	24.6	23.7	23.5	23.3	24.8	28.9	32.3
Lubes and Greases	4.2	4.5	4.6	4.8	4.9	5.0	5.1	5.3	5.7	6.0
Petrochemical Feedstock	8.6	15.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Refinery LPG	13.0	13.4	13.1	12.9	12.6	12.3	12.2	12.0	12.4	13.0
Other Products	57.8	63.7	62.7	61.7	59.6	58.8	58.2	58.3	61.1	65.1
Total Products [a]	**380.9**	**394.6**	**387.2**	**378.1**	**368.7**	**363.0**	**358.4**	**354.1**	**364.2**	**383.4**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Motor Gasoline	129.5	132.9	128.7	123.0	119.3	117.2	115.4	113.4	117.8	121.3
Av. Turbo - Kerosene (Jet A-1)	16.5	18.2	18.9	19.4	19.8	20.0	20.4	21.3	22.3	23.6
- Naphtha (Jet B)	8.5	5.9	5.9	5.8	5.6	5.5	5.4	5.0	4.3	4.6
-Total	25.0	24.1	24.8	25.2	25.4	25.5	25.8	26.3	26.6	28.1
Light Fuel and Kerosene	4.3	3.6	3.8	3.9	3.9	4.0	4.2	4.6	5.2	5.5
Diesel Fuel Oil	106.5	108.2	110.8	111.6	112.7	113.6	114.7	118.3	124.7	131.8
Heavy Fuel Oil	1.9	2.0	1.8	1.5	1.5	1.4	1.4	1.5	1.6	1.7
Asphalt	29.4	26.0	28.0	27.4	28.4	30.0	30.3	34.5	41.1	39.8
Lubes and Greases	4.2	4.5	4.5	4.7	4.8	4.9	5.0	5.2	5.5	5.8
Petrochemical Feedstock	8.6	15.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Refinery LPG	13.0	13.4	13.3	13.1	13.1	13.1	13.2	13.5	14.4	14.9
Other Products	57.8	63.7	64.1	63.9	64.4	65.4	66.4	69.8	76.1	79.0
Total Products [a]	**380.9**	**394.6**	**391.8**	**386.3**	**385.4**	**387.1**	**388.3**	**399.1**	**425.0**	**439.8**

Note: [a] Fuels used to generate electricity exports are not included.

(Petajoules)

British Columbia

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	1.4	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Motor Gasoline	128.5	124.7	123.1	121.6	119.9	118.7	117.6	116.4	117.6	123.2
Av. Turbo - Kerosene (Jet A-1)	16.6	23.8	25.2	25.7	26.1	26.3	26.4	26.7	27.8	28.3
- Naphtha (Jet B)	7.8	4.3	4.3	4.2	4.1	4.0	3.9	3.5	3.0	3.0
-Total	24.4	28.1	29.5	30.0	30.2	30.2	30.3	30.2	30.8	31.3
Light Fuel and Kerosene	23.3	22.3	21.4	20.2	18.3	17.9	17.2	16.4	15.4	14.4
Diesel Fuel Oil	94.4	102.0	103.3	105.1	106.9	109.1	111.0	116.6	124.2	133.3
Heavy Fuel Oil	32.3	35.7	37.4	35.1	32.8	31.4	30.1	26.2	22.5	18.4
Asphalt	11.0	12.4	12.1	11.9	11.8	12.0	12.2	12.7	14.3	16.2
Lubes and Greases	3.8	4.1	4.3	4.6	4.8	5.0	5.2	5.5	5.9	6.2
Petrochemical Feedstock	0.9	1.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Refinery LPG	6.2	6.5	6.5	6.5	6.4	6.4	6.4	6.4	6.6	6.9
Other Products	24.6	31.2	31.5	31.6	31.7	32.0	32.3	33.4	35.6	38.4
Total Products [a]	**350.7**	**369.9**	**371.1**	**368.4**	**364.8**	**364.7**	**364.3**	**365.7**	**374.8**	**390.1**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Aviation Gasoline	1.4	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Motor Gasoline	128.5	124.7	122.7	120.8	118.9	117.2	115.7	112.9	112.6	116.6
Av. Turbo - Kerosene (Jet A-1)	16.6	23.8	24.8	25.4	25.9	26.2	26.7	27.8	29.2	30.8
- Naphtha (Jet B)	7.8	4.3	4.2	4.2	4.0	4.0	3.9	3.6	3.1	3.3
-Total	24.4	28.1	29.0	29.6	29.9	30.2	30.6	31.5	32.3	34.1
Light Fuel and Kerosene	23.3	22.3	21.0	20.1	18.6	16.8	15.8	12.7	10.9	11.0
Diesel Fuel Oil	94.4	102.0	102.8	104.7	107.5	110.1	112.4	117.8	126.9	139.2
Heavy Fuel Oil	32.3	35.7	34.8	30.9	27.7	26.3	25.2	21.5	20.8	18.8
Asphalt	11.0	12.4	12.1	11.9	11.9	12.1	12.4	13.0	14.2	16.8
Lubes and Greases	3.8	4.1	4.2	4.4	4.5	4.6	4.7	4.9	5.1	5.5
Petrochemical Feedstock	0.9	1.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Refinery LPG	6.2	6.5	6.5	6.4	6.3	6.3	6.3	6.3	6.4	6.8
Other Products	24.6	31.2	31.2	31.2	31.3	31.5	31.8	32.7	35.0	38.1
Total Products [a]	**350.7**	**369.9**	**366.1**	**361.9**	**358.6**	**357.1**	**356.8**	**355.2**	**366.2**	**388.9**

Note: [a] Fuels used to generate electricity exports are not included.

Appendix 5

Table A5-1

Generating Capacity by Fuel Type - Canada, Provinces and Territories

Gigawatts **Canada**

Low Case

Type of Capacity	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Fossil Fuelled Steam										
Coal	16.9	16.9	17.0	17.4	17.8	18.4	18.7	19.3	19.8	19.7
Oil	3.6	4.7	5.2	5.7	5.8	5.8	5.8	5.8	5.8	5.8
Gas	2.7	2.7	2.8	2.8	2.8	2.8	2.9	3.0	3.0	3.1
Other	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.9	1.1	1.2
Other Fossil Fuelled										
Comb. Turbines	2.5	2.7	2.7	2.6	2.6	2.6	2.6	2.6	2.7	3.1
Int. Combustion	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Nuclear	9.9	11.7	12.6	13.0	13.0	13.9	14.7	14.5	14.0	13.9
Hydro/Pumped Storage	56.2	56.3	56.4	57.5	57.8	58.5	58.9	61.9	68.3	71.6
Total Generating Capacity	**92.8**	**95.9**	**97.6**	**100.1**	**100.9**	**103.1**	**104.9**	**108.6**	**115.3**	**118.9**
Purchases[a]	5.5	5.5	6.2	6.2	6.2	6.2	6.2	5.4	6.7	6.9
Capacity Available	98.3	101.4	103.8	106.3	107.1	109.3	111.1	114.0	122.0	125.9
Sales (Export)	6.2	6.1	6.8	6.8	6.9	6.9	6.5	7.9	10.5	10.2
Domestic Peak Demand	73.2	74.7	75.9	75.9	76.3	77.7	79.5	84.2	90.0	97.1
System Peak	79.4	80.8	82.7	82.7	83.2	84.6	86.0	92.0	100.5	107.3
Remaining Capacity	18.9	20.6	21.2	23.6	23.9	24.7	25.1	22.0	21.5	18.6
% of System Peak	23.9	25.5	25.6	28.5	28.8	29.2	29.2	23.9	21.4	17.3

High Case

Type of Capacity	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Fossil Fuelled Steam										
Coal	16.9	16.9	17.0	17.4	17.8	18.4	18.8	19.4	21.4	22.3
Oil	3.6	4.7	5.2	5.7	5.8	5.9	5.9	5.9	6.0	6.0
Gas	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.9	2.8	2.8
Other	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.9	1.0	1.0
Other Fossil Fuelled										
Comb. Turbines	2.5	2.7	2.7	2.6	2.6	2.7	2.8	3.3	4.0	4.7
Int. Combustion	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Nuclear	9.9	11.7	12.6	13.0	13.0	13.9	14.7	14.5	14.0	16.6
Hydro/Pumped Storage	56.2	56.3	56.4	57.5	57.8	58.5	59.9	63.3	71.6	79.0
Total Generating Capacity	**92.8**	**95.9**	**97.6**	**100.0**	**100.9**	**103.3**	**106.1**	**110.7**	**121.3**	**133.0**
Purchases[a]	5.5	5.5	6.2	6.2	6.2	6.2	6.2	5.4	6.4	6.9
Capacity Available	98.3	101.4	103.8	106.2	107.1	109.5	112.3	116.1	127.7	139.9
Sales (Export)	6.2	6.1	6.8	6.8	6.9	6.4	6.5	7.9	10.2	10.2
Domestic Peak Demand	73.2	74.7	76.1	76.9	78.7	80.6	83.4	88.9	97.6	107.9
System Peak	79.4	80.8	82.9	83.7	85.6	87.1	89.8	96.8	107.8	118.1
Remaining Capacity	18.9	20.6	20.9	22.5	21.5	22.5	22.5	19.3	19.9	21.8
% of System Peak	23.9	25.5	25.2	26.9	25.1	25.8	25.0	20.0	18.4	18.5

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **Newfoundland**

Low Case

Type of Capacity	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	505.0	505.0	525.0	545.0	550.0	550.0	550.0	550.0	555.0	555.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	10.0	15.0
Other Fossil Fuelled										
Comb. Turbines	170.0	170.0	170.0	170.0	170.0	170.0	170.0	170.0	230.0	350.0
Int. Combustion	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	80.0	80.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	6367.0	6367.0	6367.0	6375.0	6375.0	6375.0	6375.0	6375.0	6375.0	6375.0
Total Generating Capacity	**7123.0**	**7123.0**	**7143.0**	**7171.0**	**7176.0**	**7176.0**	**7176.0**	**7181.0**	**7250.0**	**7375.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	7123.0	7123.0	7143.0	7171.0	7176.0	7176.0	7176.0	7181.0	7250.0	7375.0
Sales (Export)	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4400.0
Domestic Peak Demand	1820.0	1815.0	1831.0	1861.0	1893.0	1943.0	1983.0	2064.0	2243.0	2375.0
System Peak	6520.0	6515.0	6531.0	6561.0	6593.0	6643.0	6683.0	6764.0	6943.0	6775.0
Remaining Capacity	603.0	608.0	612.0	610.0	583.0	533.0	493.0	417.0	307.0	600.0
% of System Peak	9.2	9.3	9.4	9.3	8.8	8.0	7.4	6.2	4.4	8.9

High Case

Type of Capacity	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	505.0	505.0	525.0	545.0	550.0	720.0	720.0	720.0	725.0	725.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	10.0	15.0
Other Fossil Fuelled										
Comb. Turbines	170.0	170.0	170.0	170.0	230.0	290.0	350.0	890.0	1250.0	1250.0
Int. Combustion	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	80.0	80.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	6367.0	6367.0	6367.0	6375.0	6375.0	6375.0	6375.0	6375.0	6375.0	8073.0
Total Generating Capacity	**7123.0**	**7123.0**	**7143.0**	**7171.0**	**7236.0**	**7466.0**	**7526.0**	**8071.0**	**8440.0**	**10143.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	7123.0	7123.0	7143.0	7171.0	7236.0	7466.0	7526.0	8071.0	8440.0	10143.0
Sales (Export)	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4400.0	4400.0
Domestic Peak Demand	1820.0	1815.0	1933.0	2044.0	2197.0	2322.0	2476.0	2936.0	3450.0	3625.0
System Peak	6520.0	6515.0	6633.0	6744.0	6897.0	7022.0	7176.0	7636.0	7850.0	8025.0
Remaining Capacity	603.0	608.0	510.0	427.0	339.0	444.0	350.0	435.0	590.0	2118.0
% of System Peak	9.2	9.3	7.7	6.3	4.9	6.3	4.9	5.7	7.5	26.4

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

(Megawatts)

Nova Scotia

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	861.0	861.0	1013.0	1013.0	1013.0	1163.0	1163.0	1163.0	1313.0	1463.0
Oil	701.0	701.0	556.0	556.0	556.0	556.0	556.0	556.0	556.0	556.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.0	38.0	38.0
Other	19.0	19.0	19.0	19.0	19.0	19.0	19.0	49.0	59.0	59.0
Other Fossil Fuelled										
Comb. Turbines	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0
Total Generating Capacity	**2173.0**	**2173.0**	**2180.0**	**2180.0**	**2180.0**	**2330.0**	**2330.0**	**2388.0**	**2558.0**	**2708.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	2173.0	2173.0	2180.0	2180.0	2180.0	2330.0	2330.0	2388.0	2558.0	2708.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	1469.0	1484.0	1546.0	1606.0	1650.0	1713.0	1748.0	1868.0	2033.0	2127.0
System Peak	1469.0	1484.0	1546.0	1606.0	1650.0	1713.0	1748.0	1868.0	2033.0	2127.0
Remaining Capacity	704.0	689.0	634.0	574.0	530.0	617.0	582.0	520.0	525.0	581.0
% of System Peak	47.9	46.4	41.0	35.7	32.1	36.0	33.3	27.8	25.8	27.3

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	861.0	861.0	1013.0	1013.0	1013.0	1163.0	1163.0	1163.0	1463.0	1613.0
Oil	701.0	701.0	556.0	556.0	556.0	556.0	556.0	556.0	556.0	556.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.0	38.0	38.0
Other	19.0	19.0	19.0	19.0	19.0	19.0	19.0	49.0	59.0	59.0
Other Fossil Fuelled										
Comb. Turbines	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0
Total Generating Capacity	**2173.0**	**2173.0**	**2180.0**	**2180.0**	**2180.0**	**2330.0**	**2330.0**	**2388.0**	**2708.0**	**2858.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	2173.0	2173.0	2180.0	2180.0	2180.0	2330.0	2330.0	2388.0	2708.0	2858.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	1469.0	1484.0	1537.0	1603.0	1663.0	1736.0	1784.0	1942.0	2161.0	2341.0
System Peak	1469.0	1484.0	1537.0	1603.0	1663.0	1736.0	1784.0	1942.0	2161.0	2341.0
Remaining Capacity	704.0	689.0	643.0	577.0	517.0	594.0	546.0	446.0	547.0	517.0
% of System Peak	47.9	46.4	41.8	36.0	31.1	34.2	30.6	23.0	25.3	22.1

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **Prince Edward Island**

Low Case

Type of Capacity	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Fuelled										
Comb. Turbines	41.0	41.0	41.0	51.0	51.0	51.0	51.0	51.0	61.0	61.0
Int. Combustion	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Generating Capacity	**123.0**	**123.0**	**123.0**	**133.0**	**133.0**	**133.0**	**133.0**	**133.0**	**143.0**	**143.0**
Purchases[a]	20.0	20.0	20.0	20.0	35.0	35.0	35.0	50.0	50.0	65.0
Capacity Available	143.0	143.0	143.0	153.0	168.0	168.0	168.0	183.0	193.0	208.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	109.0	119.0	123.0	127.0	131.0	134.0	138.0	147.0	160.0	172.0
System Peak	109.0	119.0	123.0	127.0	131.0	134.0	138.0	147.0	160.0	172.0
Remaining Capacity	34.0	24.0	20.0	26.0	37.0	34.0	30.0	36.0	33.0	36.0
% of System Peak	31.2	20.2	16.3	20.5	28.2	25.4	21.7	24.5	20.6	20.9

High Case

Type of Capacity	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Fuelled										
Comb. Turbines	41.0	41.0	41.0	51.0	51.0	51.0	51.0	61.0	61.0	61.0
Int. Combustion	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Generating Capacity	**123.0**	**123.0**	**123.0**	**133.0**	**133.0**	**133.0**	**133.0**	**143.0**	**143.0**	**143.0**
Purchases[a]	20.0	20.0	20.0	20.0	35.0	35.0	35.0	50.0	50.0	65.0
Capacity Available	143.0	143.0	143.0	153.0	168.0	168.0	168.0	193.0	193.0	208.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	109.0	119.0	123.0	127.0	131.0	135.0	139.0	149.0	164.0	178.0
System Peak	109.0	119.0	123.0	127.0	131.0	135.0	139.0	149.0	164.0	178.0
Remaining Capacity	34.0	24.0	20.0	26.0	37.0	33.0	29.0	44.0	29.0	30.0
% of System Peak	31.2	20.2	16.3	20.5	28.2	24.4	20.9	29.5	17.7	16.9

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

(Megawatts)

New Brunswick

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	305.0	305.0	305.0	290.0	305.0	305.0	305.0	905.0	905.0	905.0
Oil	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0	57.0	57.0
Other	41.0	41.0	41.0	55.0	61.0	61.0	111.0	111.0	111.0	111.0
Other Fossil Fuelled										
Comb. Turbines	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	181.0	337.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	899.0	899.0	899.0	899.0	899.0	899.0	899.0	899.0	899.0	899.0
Total Generating Capacity	**3377.0**	**3377.0**	**3377.0**	**3376.0**	**3397.0**	**3397.0**	**3447.0**	**4082.0**	**4260.0**	**4416.0**
Purchases[a]	0.0	0.0	675.0	675.0	675.0	675.0	675.0	0.0	0.0	0.0
Capacity Available	3377.0	3377.0	4052.0	4051.0	4072.0	4072.0	4122.0	4082.0	4260.0	4416.0
Sales (Export)	402.0	402.0	402.0	402.0	417.0	417.0	352.0	337.0	337.0	352.0
Domestic Peak Demand	2199.0	2263.0	2392.0	2512.0	2556.0	2688.0	2757.0	2870.0	3012.0	3147.0
System Peak	2601.0	2665.0	2794.0	2914.0	2973.0	3105.0	3109.0	3207.0	3349.0	3499.0
Remaining Capacity	776.0	712.0	1258.0	1137.0	1099.0	967.0	1013.0	875.0	911.0	917.0
% of System Peak	29.8	26.7	45.0	39.0	37.0	31.1	32.6	27.3	27.2	26.2

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	305.0	305.0	305.0	290.0	305.0	305.0	305.0	905.0	905.0	1105.0
Oil	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0	1476.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0	57.0	57.0
Other	41.0	41.0	41.0	55.0	61.0	61.0	111.0	111.0	111.0	111.0
Other Fossil Fuelled										
Comb. Turbines	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	181.0	337.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	899.0	899.0	899.0	899.0	899.0	899.0	899.0	899.0	899.0	899.0
Total Generating Capacity	**3377.0**	**3377.0**	**3377.0**	**3376.0**	**3397.0**	**3397.0**	**3447.0**	**4082.0**	**4260.0**	**4616.0**
Purchases[a]	0.0	0.0	675.0	675.0	675.0	675.0	675.0	0.0	0.0	0.0
Capacity Available	3377.0	3377.0	4052.0	4051.0	4072.0	4072.0	4122.0	4082.0	4260.0	4616.0
Sales (Export)	402.0	402.0	402.0	402.0	417.0	417.0	352.0	337.0	337.0	352.0
Domestic Peak Demand	2199.0	2263.0	2373.0	2507.0	2582.0	2728.0	2809.0	2961.0	3186.0	3440.0
System Peak	2601.0	2665.0	2775.0	2909.0	2999.0	3145.0	3161.0	3298.0	3523.0	3792.0
Remaining Capacity	776.0	712.0	1277.0	1142.0	1073.0	927.0	961.0	784.0	737.0	824.0
% of System Peak	29.8	26.7	46.0	39.3	35.8	29.5	30.4	23.8	20.9	21.7

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **Atlantic**

Low Case

Type of Capacity	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Fossil Fuelled Steam										
Coal	1166.0	1166.0	1318.0	1303.0	1318.0	1468.0	1468.0	2068.0	2218.0	2368.0
Oil	2753.0	2753.0	2628.0	2648.0	2653.0	2653.0	2653.0	2653.0	2658.0	2658.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.0	95.0	95.0
Other	60.0	60.0	60.0	74.0	80.0	80.0	130.0	165.0	180.0	185.0
Other Fossil Fuelled										
Comb. Turbines	441.0	441.0	441.0	451.0	451.0	451.0	451.0	451.0	677.0	953.0
Int. Combustion	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	93.0	93.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	7652.0	7652.0	7652.0	7660.0	7660.0	7660.0	7660.0	7660.0	7660.0	7660.0
Total Generating Capacity	**12796.0**	**12796.0**	**12823.0**	**12860.0**	**12886.0**	**13036.0**	**13086.0**	**13784.0**	**14211.0**	**14642.0**
Purchases[a]	20.0	20.0	695.0	695.0	710.0	710.0	710.0	50.0	50.0	65.0
Capacity Available	12816.0	12816.0	13518.0	13555.0	13596.0	13746.0	13796.0	13834.0	14261.0	14707.0
Sales (Export)	5102.0	5102.0	5102.0	5102.0	5117.0	5117.0	5052.0	5037.0	5037.0	4752.0
Domestic Peak Demand	5597.0	5681.0	5892.0	6106.0	6230.0	6478.0	6626.0	6949.0	7448.0	7821.0
System Peak	10699.0	10783.0	10994.0	11208.0	11347.0	11595.0	11678.0	11986.0	12485.0	12573.0
Remaining Capacity	2117.0	2033.0	2524.0	2347.0	2249.0	2151.0	2118.0	1848.0	1776.0	2134.0
% of System Peak	19.8	18.9	23.0	20.9	19.8	18.6	18.1	15.4	14.2	17.0

High Case

Type of Capacity	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Fossil Fuelled Steam										
Coal	1166.0	1166.0	1318.0	1303.0	1318.0	1468.0	1468.0	2068.0	2368.0	2718.0
Oil	2753.0	2753.0	2628.0	2648.0	2653.0	2823.0	2823.0	2823.0	2828.0	2828.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.0	95.0	95.0
Other	60.0	60.0	60.0	74.0	80.0	80.0	130.0	165.0	180.0	185.0
Other Fossil Fuelled										
Comb. Turbines	441.0	441.0	441.0	451.0	511.0	571.0	631.0	1181.0	1697.0	1853.0
Int. Combustion	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	93.0	93.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	7652.0	7652.0	7652.0	7660.0	7660.0	7660.0	7660.0	7660.0	7660.0	9358.0
Total Generating Capacity	**12796.0**	**12796.0**	**12823.0**	**12860.0**	**12946.0**	**13326.0**	**13436.0**	**14684.0**	**15551.0**	**17760.0**
Purchases[a]	20.0	20.0	695.0	695.0	710.0	710.0	710.0	50.0	50.0	65.0
Capacity Available	12816.0	12816.0	13518.0	13555.0	13656.0	14036.0	14146.0	14734.0	15601.0	17825.0
Sales (Export)	5102.0	5102.0	5102.0	5102.0	5117.0	5117.0	5052.0	5037.0	4737.0	4752.0
Domestic Peak Demand	5597.0	5681.0	5966.0	6281.0	6573.0	6921.0	7208.0	7988.0	8961.0	9584.0
System Peak	10699.0	10783.0	11068.0	11383.0	11690.0	12038.0	12260.0	13025.0	13698.0	14336.0
Remaining Capacity	2117.0	2033.0	2450.0	2172.0	1966.0	1998.0	1886.0	1709.0	1903.0	3489.0
% of System Peak	19.8	18.9	22.1	19.1	16.8	16.6	15.4	13.1	13.9	24.3

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **Quebec**

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	664.0	664.0	664.0	660.0	660.0	660.0	660.0	650.0	650.0	650.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	4.0	4.0	4.0	10.0	10.0	10.0	10.0	20.0	20.0	20.0
Other Fossil Fuelled										
Comb. Turbines	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0
Int. Combustion	62.0	62.0	62.0	62.0	119.0	119.0	119.0	119.0	119.0	119.0
Nuclear	685.0	685.0	685.0	685.0	685.0	685.0	685.0	685.0	685.0	685.0
Hydro/Pumped Storage	25214.0	25220.0	25360.0	26390.0	26450.0	26498.0	26548.0	29094.0	33635.0	35828.0
Total Generating Capacity	**27070.0**	**27076.0**	**27216.0**	**28248.0**	**28365.0**	**28413.0**	**28463.0**	**31009.0**	**35550.0**	**37743.0**
Purchases[a]	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4400.0
Capacity Available	31770.0	31776.0	31916.0	32948.0	33065.0	33113.0	33163.0	35709.0	40250.0	42143.0
Sales (Export)	237.0	287.0	962.0	962.0	1062.0	1062.0	1161.0	1336.0	3186.0	3186.0
Domestic Peak Demand	27274.0	27748.0	27692.0	27208.0	27256.0	27902.0	28595.0	30512.0	32982.0	35388.0
System Peak	27511.0	28035.0	28654.0	28170.0	28318.0	28964.0	29756.0	31848.0	36168.0	38574.0
Remaining Capacity	4259.0	3741.0	3262.0	4778.0	4747.0	4149.0	3407.0	3861.0	4082.0	3569.0
% of System Peak	15.5	13.3	11.4	17.0	16.8	14.3	11.4	12.1	11.3	9.3

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	664.0	664.0	664.0	660.0	660.0	660.0	660.0	650.0	650.0	650.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	4.0	4.0	4.0	10.0	10.0	10.0	10.0	20.0	20.0	20.0
Other Fossil Fuelled										
Comb. Turbines	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0	441.0
Int. Combustion	62.0	62.0	62.0	62.0	119.0	119.0	119.0	119.0	119.0	119.0
Nuclear	685.0	685.0	685.0	685.0	685.0	685.0	685.0	685.0	685.0	685.0
Hydro/Pumped Storage	25214.0	25220.0	25360.0	26390.0	26450.0	26498.0	27499.0	29882.0	35828.0	40431.0
Total Generating Capacity	**27070.0**	**27076.0**	**27216.0**	**28248.0**	**28365.0**	**28413.0**	**29414.0**	**31797.0**	**37743.0**	**42346.0**
Purchases[a]	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4400.0	4400.0
Capacity Available	31770.0	31776.0	31916.0	32948.0	33065.0	33113.0	34114.0	36497.0	42143.0	46746.0
Sales (Export)	237.0	287.0	962.0	962.0	1062.0	1062.0	1161.0	1336.0	3186.0	3186.0
Domestic Peak Demand	27274.0	27748.0	27691.0	27471.0	27992.0	28629.0	29536.0	31758.0	35250.0	39246.0
System Peak	27511.0	28035.0	28653.0	28433.0	29054.0	29691.0	30697.0	33094.0	38436.0	42432.0
Remaining Capacity	4259.0	3741.0	3263.0	4515.0	4011.0	3422.0	3417.0	3403.0	3707.0	4314.0
% of System Peak	15.5	13.3	11.4	15.9	13.8	11.5	11.1	10.3	9.6	10.2

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Ontario

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	8891.0	8891.0	8891.0	8891.0	8891.0	8891.0	8991.0	8991.0	8991.0	8991.0
Oil	50.0	1166.0	1724.0	2282.0	2302.0	2302.0	2302.0	2302.0	2332.0	2332.0
Gas	165.0	165.0	188.0	196.0	204.0	212.0	240.0	276.0	291.0	291.0
Other	90.0	90.0	106.0	114.0	122.0	130.0	138.0	164.0	164.0	164.0
Other Fossil Fuelled										
Comb. Turbines	729.0	837.0	837.0	842.0	842.0	852.0	852.0	852.0	872.0	872.0
Int. Combustion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	8589.0	10424.0	11305.0	11671.0	11671.0	12552.0	13433.0	13208.0	12692.0	12597.0
Hydro/Pumped Storage	7164.0	7164.0	7164.0	7209.0	7209.0	7209.0	7209.0	7209.0	8276.0	8276.0
Total Generating Capacity	**25678.0**	**28737.0**	**30215.0**	**31205.0**	**31241.0**	**32148.0**	**33165.0**	**33002.0**	**33618.0**	**33523.0**
Purchases[a]	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	256.0	256.0
Capacity Available	25734.0	28793.0	30271.0	31261.0	31297.0	32204.0	33221.0	33058.0	33874.0	33779.0
Sales (Export)	635.0	435.0	435.0	435.0	435.0	435.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	21569.0	22157.0	22729.0	22988.0	23205.0	23623.0	24296.0	25625.0	26427.0	27914.0
System Peak	22204.0	22592.0	23164.0	23423.0	23640.0	24058.0	24296.0	25625.0	26427.0	27914.0
Remaining Capacity	3530.0	6201.0	7107.0	7838.0	7657.0	8146.0	8925.0	7433.0	7447.0	5865.0
% of System Peak	15.9	27.4	30.7	33.5	32.4	33.9	36.7	29.0	28.2	21.0

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	8891.0	8891.0	8891.0	8891.0	8891.0	8891.0	8991.0	8991.0	8991.0	8991.0
Oil	50.0	1166.0	1724.0	2282.0	2302.0	2302.0	2302.0	2302.0	2332.0	2332.0
Gas	165.0	165.0	188.0	196.0	204.0	212.0	240.0	276.0	291.0	291.0
Other	90.0	90.0	106.0	114.0	122.0	130.0	138.0	164.0	164.0	164.0
Other Fossil Fuelled										
Comb. Turbines	729.0	837.0	837.0	842.0	842.0	852.0	852.0	852.0	872.0	976.0
Int. Combustion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	8589.0	10424.0	11305.0	11671.0	11671.0	12552.0	13433.0	13208.0	12692.0	15240.0
Hydro/Pumped Storage	7164.0	7164.0	7164.0	7209.0	7209.0	7209.0	7209.0	7607.0	8276.0	8276.0
Total Generating Capacity	**25678.0**	**28737.0**	**30215.0**	**31205.0**	**31241.0**	**32148.0**	**33165.0**	**33400.0**	**33618.0**	**36270.0**
Purchases[a]	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	256.0	256.0
Capacity Available	25734.0	28793.0	30271.0	31261.0	31297.0	32204.0	33221.0	33456.0	33874.0	36526.0
Sales (Export)	635.0	435.0	435.0	435.0	435.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	21569.0	22157.0	22694.0	23193.0	23875.0	24430.0	25448.0	26337.0	27465.0	30093.0
System Peak	22204.0	22592.0	23129.0	23628.0	24310.0	24430.0	25448.0	26337.0	27465.0	30093.0
Remaining Capacity	3530.0	6201.0	7142.0	7633.0	6987.0	7774.0	7773.0	7119.0	6409.0	6433.0
% of System Peak	15.9	27.4	30.9	32.3	28.7	31.8	30.5	27.0	23.3	21.4

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

(Megawatts)

Manitoba

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	369.0	369.0	369.0	369.0	369.0	369.0	369.0	369.0	105.0	105.0
Oil	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Gas	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Other	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Other Fossil Fuelled										
Comb. Turbines	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Int. Combustion	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	3548.0	3548.0	3548.0	3548.0	3804.0	4444.0	4828.0	4828.0	5602.0	6118.0
Total Generating Capacity	**4049.0**	**4049.0**	**4049.0**	**4049.0**	**4305.0**	**4945.0**	**5329.0**	**5329.0**	**5814.0**	**6330.0**
Purchases[a]	300.0	300.0	300.0	300.0	300.0	300.0	300.0	200.0	200.0	200.0
Capacity Available	4349.0	4349.0	4349.0	4349.0	4605.0	5245.0	5629.0	5529.0	6014.0	6530.0
Sales (Export)	100.0	160.0	160.0	160.0	160.0	160.0	160.0	500.0	1250.0	1250.0
Domestic Peak Demand	3082.0	3065.0	3231.0	3256.0	3277.0	3388.0	3432.0	3629.0	3910.0	4320.0
System Peak	3182.0	3225.0	3391.0	3416.0	3437.0	3548.0	3592.0	4129.0	5160.0	5570.0
Remaining Capacity	1167.0	1124.0	958.0	933.0	1168.0	1697.0	2037.0	1400.0	854.0	960.0
% of System Peak	36.7	34.9	28.3	27.3	34.0	47.8	56.7	33.9	16.6	17.2

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	369.0	369.0	369.0	369.0	369.0	369.0	369.0	369.0	105.0	105.0
Oil	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Gas	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Other	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Other Fossil Fuelled										
Comb. Turbines	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0
Int. Combustion	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	3548.0	3548.0	3548.0	3548.0	3804.0	4444.0	4828.0	4828.0	6118.0	6206.0
Total Generating Capacity	**4049.0**	**4049.0**	**4049.0**	**4049.0**	**4305.0**	**4945.0**	**5329.0**	**5329.0**	**6330.0**	**6418.0**
Purchases[a]	300.0	300.0	300.0	300.0	300.0	300.0	300.0	200.0	200.0	200.0
Capacity Available	4349.0	4349.0	4349.0	4349.0	4605.0	5245.0	5629.0	5529.0	6530.0	6618.0
Sales (Export)	100.0	160.0	160.0	160.0	160.0	160.0	160.0	500.0	1250.0	1250.0
Domestic Peak Demand	3082.0	3065.0	3237.0	3280.0	3312.0	3400.0	3466.0	3693.0	4037.0	4492.0
System Peak	3182.0	3225.0	3397.0	3440.0	3472.0	3560.0	3626.0	4193.0	5287.0	5742.0
Remaining Capacity	1167.0	1124.0	952.0	909.0	1133.0	1685.0	2003.0	1336.0	1243.0	876.0
% of System Peak	36.7	34.9	28.0	26.4	32.6	47.3	55.2	31.9	23.5	15.3

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **Saskatchewan**

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	1595.0	1595.0	1595.0	1595.0	1595.0	1595.0	1875.0	1875.0	1875.0	1875.0
Oil	7.0	7.0	7.0	7.0	7.0	10.0	10.0	10.0	10.0	10.0
Gas	131.0	131.0	131.0	131.0	131.0	138.0	138.0	138.0	138.0	138.0
Other	36.0	36.0	36.0	36.0	36.0	41.0	41.0	41.0	46.0	46.0
Other Fossil Fuelled										
Comb. Turbines	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0
Int. Combustion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	821.0	821.0	821.0	821.0	821.0	821.0	821.0	821.0	921.0	1221.0
Total Generating Capacity	**2747.0**	**2747.0**	**2747.0**	**2747.0**	**2747.0**	**2762.0**	**3042.0**	**3042.0**	**3147.0**	**3447.0**
Purchases[a]	100.0	100.0	150.0	150.0	150.0	150.0	150.0	100.0	100.0	100.0
Capacity Available	2847.0	2847.0	2897.0	2897.0	2897.0	2912.0	3192.0	3142.0	3247.0	3547.0
Sales (Export)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Domestic Peak Demand	2129.0	2131.0	2286.0	2273.0	2250.0	2289.0	2321.0	2454.0	2721.0	2973.0
System Peak	2139.0	2141.0	2296.0	2283.0	2260.0	2299.0	2331.0	2464.0	2731.0	2983.0
Remaining Capacity	708.0	706.0	601.0	614.0	637.0	613.0	861.0	678.0	516.0	564.0
% of System Peak	33.1	33.0	26.2	26.9	28.2	26.7	36.9	27.5	18.9	18.9

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	1595.0	1595.0	1595.0	1595.0	1595.0	1595.0	1875.0	1875.0	2155.0	2155.0
Oil	7.0	7.0	7.0	7.0	7.0	10.0	10.0	10.0	10.0	10.0
Gas	131.0	131.0	131.0	131.0	131.0	138.0	138.0	138.0	138.0	138.0
Other	36.0	36.0	36.0	36.0	36.0	41.0	41.0	41.0	46.0	46.0
Other Fossil Fuelled										
Comb. Turbines	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	257.0
Int. Combustion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	821.0	821.0	821.0	821.0	821.0	821.0	821.0	821.0	1221.0	1221.0
Total Generating Capacity	**2747.0**	**2747.0**	**2747.0**	**2747.0**	**2747.0**	**2762.0**	**3042.0**	**3042.0**	**3727.0**	**3827.0**
Purchases[a]	100.0	100.0	150.0	150.0	150.0	150.0	150.0	100.0	100.0	100.0
Capacity Available	2847.0	2847.0	2897.0	2897.0	2897.0	2912.0	3192.0	3142.0	3827.0	3927.0
Sales (Export)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Domestic Peak Demand	2129.0	2131.0	2307.0	2337.0	2359.0	2413.0	2462.0	2658.0	3064.0	3386.0
System Peak	2139.0	2141.0	2317.0	2347.0	2369.0	2423.0	2472.0	2668.0	3074.0	3396.0
Remaining Capacity	708.0	706.0	580.0	550.0	528.0	489.0	720.0	474.0	753.0	531.0
% of System Peak	33.1	33.0	25.0	23.4	22.3	20.2	29.1	17.8	24.5	15.6

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **Alberta**

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	4845.0	4845.0	4845.0	5251.0	5634.0	6040.0	6040.0	6040.0	5978.0	5768.0
Oil	7.0	7.0	7.0	7.0	10.0	10.0	10.0	10.0	10.0	10.0
Gas	1330.0	1330.0	1359.0	1375.0	1355.0	1380.0	1405.0	1475.0	1405.0	1515.0
Other	47.0	60.0	89.0	113.0	135.0	160.0	185.0	325.0	465.0	575.0
Other Fossil Fuelled										
Comb. Turbines	573.0	581.0	581.0	531.0	501.0	501.0	501.0	511.0	406.0	486.0
Int. Combustion	66.0	66.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0
Total Generating Capacity	**7602.0**	**7623.0**	**7685.0**	**8081.0**	**8439.0**	**8895.0**	**8945.0**	**9165.0**	**9068.0**	**9158.0**
Purchases[a]	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Capacity Available	7902.0	7923.0	7985.0	8381.0	8739.0	9195.0	9245.0	9465.0	9368.0	9458.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	5322.0	5467.0	5543.0	5608.0	5587.0	5550.0	5617.0	6047.0	6802.0	7774.0
System Peak	5322.0	5467.0	5543.0	5608.0	5587.0	5550.0	5617.0	6047.0	6802.0	7774.0
Remaining Capacity	2580.0	2456.0	2442.0	2773.0	3152.0	3645.0	3628.0	3418.0	2566.0	1684.0
% of System Peak	48.5	44.9	44.1	49.4	56.4	65.7	64.6	56.5	37.7	21.7

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	4845.0	4845.0	4845.0	5251.0	5640.0	6052.0	6052.0	6065.0	7153.0	7705.0
Oil	7.0	7.0	7.0	7.0	10.0	10.0	10.0	10.0	10.0	10.0
Gas	1330.0	1330.0	1330.0	1330.0	1308.0	1320.0	1320.0	1313.0	1205.0	1231.0
Other	47.0	60.0	61.0	68.0	106.0	138.0	163.0	275.0	365.0	427.0
Other Fossil Fuelled										
Comb. Turbines	573.0	581.0	581.0	531.0	501.0	501.0	501.0	511.0	706.0	986.0
Int. Combustion	66.0	66.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0
Total Generating Capacity	**7602.0**	**7623.0**	**7628.0**	**7991.0**	**8369.0**	**8825.0**	**8850.0**	**8978.0**	**10243.0**	**11163.0**
Purchases[a]	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Capacity Available	7902.0	7923.0	7928.0	8291.0	8669.0	9125.0	9150.0	9278.0	10543.0	11463.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	5322.0	5467.0	5716.0	5822.0	6068.0	6237.0	6508.0	7322.0	8695.0	9574.0
System Peak	5322.0	5467.0	5716.0	5822.0	6068.0	6237.0	6508.0	7322.0	8695.0	9574.0
Remaining Capacity	2580.0	2456.0	2212.0	2469.0	2601.0	2888.0	2642.0	1956.0	1848.0	1889.0
% of System Peak	48.5	44.9	38.7	42.4	42.9	46.3	40.6	26.7	21.3	19.7

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **Prairies**

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	6809.0	6809.0	6809.0	7215.0	7598.0	8004.0	8284.0	8284.0	7958.0	7748.0
Oil	29.0	29.0	29.0	29.0	32.0	35.0	35.0	35.0	35.0	35.0
Gas	1515.0	1515.0	1544.0	1560.0	1540.0	1572.0	1597.0	1667.0	1597.0	1707.0
Other	91.0	104.0	133.0	157.0	179.0	209.0	234.0	374.0	519.0	629.0
Other Fossil Fuelled										
Comb. Turbines	755.0	763.0	763.0	713.0	683.0	683.0	683.0	693.0	563.0	643.0
Int. Combustion	96.0	96.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nuclear										
Hydro/Pumped Storage	5103.0	5103.0	5103.0	5103.0	5359.0	5999.0	6383.0	6383.0	7257.0	8073.0
Total Generating Capacity	**14398.0**	**14419.0**	**14481.0**	**14877.0**	**15491.0**	**16602.0**	**17316.0**	**17536.0**	**18029.0**	**18935.0**
Purchases[a]	700.0	700.0	750.0	750.0	750.0	750.0	750.0	600.0	600.0	600.0
Capacity Available	15098.0	15119.0	15231.0	15627.0	16241.0	17352.0	18066.0	18136.0	18629.0	19535.0
Sales (Export)	110.0	170.0	170.0	170.0	170.0	170.0	170.0	510.0	1260.0	1260.0
Domestic Peak Demand	10533.0	10663.0	11060.0	11137.0	11114.0	11227.0	11370.0	12130.0	13433.0	15067.0
System Peak	10643.0	10833.0	11230.0	11307.0	11284.0	11397.0	11540.0	12640.0	14693.0	16327.0
Remaining Capacity	4455.0	4286.0	4001.0	4320.0	4957.0	5955.0	6526.0	5496.0	3936.0	3208.0
% of System Peak	41.9	39.6	35.6	38.2	43.9	52.3	56.6	43.5	26.8	19.6

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	6809.0	6809.0	6809.0	7215.0	7604.0	8016.0	8296.0	8309.0	9413.0	9965.0
Oil	29.0	29.0	29.0	29.0	32.0	35.0	35.0	35.0	35.0	35.0
Gas	1515.0	1515.0	1515.0	1515.0	1493.0	1512.0	1512.0	1505.0	1397.0	1423.0
Other	91.0	104.0	105.0	112.0	150.0	187.0	212.0	324.0	419.0	481.0
Other Fossil Fuelled										
Comb. Turbines	755.0	763.0	763.0	713.0	683.0	683.0	683.0	693.0	863.0	1243.0
Int. Combustion	96.0	96.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nuclear										
Hydro/Pumped Storage	5103.0	5103.0	5103.0	5103.0	5359.0	5999.0	6383.0	6383.0	8073.0	8161.0
Total Generating Capacity	**14398.0**	**14419.0**	**14424.0**	**14787.0**	**15421.0**	**16532.0**	**17221.0**	**17349.0**	**20300.0**	**21408.0**
Purchases[a]	700.0	700.0	750.0	750.0	750.0	750.0	750.0	600.0	600.0	600.0
Capacity Available	15098.0	15119.0	15174.0	15537.0	16171.0	17282.0	17971.0	17949.0	20900.0	22008.0
Sales (Export)	110.0	0.0	0.0	0.0	0.0	0.0	0.0	510.0	1260.0	1260.0
Domestic Peak Demand	10533.0	10663.0	11260.0	11439.0	11739.0	12050.0	12436.0	13673.0	15796.0	17452.0
System Peak	10643.0	10663.0	11260.0	11439.0	11739.0	12050.0	12436.0	14183.0	17056.0	18712.0
Remaining Capacity	4455.0	4456.0	3914.0	4098.0	4432.0	5232.0	5535.0	3766.0	3844.0	3296.0
% of System Peak	41.9	41.8	34.8	35.8	37.8	43.4	44.5	26.6	22.5	17.6

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

(Megawatts)

British Columbia

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	600.0	600.0
Oil	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Gas	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0
Other	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0
Other Fossil Fuelled										
Comb. Turbines	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Int. Combustion	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	10991.0	10991.0	10991.0	10991.0	10991.0	10991.0	10991.0	11391.0	11391.0	11593.0
Total Generating Capacity	**12579.0**	**12579.0**	**12579.0**	**12579.0**	**12579.0**	**12579.0**	**12579.0**	**12979.0**	**13579.0**	**13781.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1100.0	1600.0
Capacity Available	12579.0	12579.0	12579.0	12579.0	12579.0	12579.0	12579.0	12979.0	14679.0	15381.0
Sales (Export)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	1000.0	1000.0	1000.0
Domestic Peak Demand	7830.0	8102.0	8154.0	8132.0	8103.0	8126.0	8252.0	8561.0	9331.0	10411.0
System Peak	7930.0	8202.0	8254.0	8232.0	8203.0	8226.0	8352.0	9561.0	10331.0	11411.0
Remaining Capacity	4649.0	4377.0	4325.0	4347.0	4376.0	4353.0	4227.0	3418.0	4348.0	3970.0
% of System Peak	58.6	53.4	52.4	52.8	53.3	52.9	50.6	35.7	42.1	34.8

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	600.0	600.0
Oil	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Gas	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0
Other	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0
Other Fossil Fuelled										
Comb. Turbines	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Int. Combustion	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	10991.0	10991.0	10991.0	10991.0	10991.0	10991.0	10991.0	11593.0	11593.0	12673.0
Total Generating Capacity	**12579.0**	**12579.0**	**12579.0**	**12579.0**	**12579.0**	**12579.0**	**12579.0**	**13181.0**	**13781.0**	**14861.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1100.0	1600.0
Capacity Available	12579.0	12579.0	12579.0	12579.0	12579.0	12579.0	12579.0	13181.0	14881.0	16461.0
Sales (Export)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	1000.0	1000.0	1000.0
Domestic Peak Demand	7830.0	8102.0	8110.0	8134.0	8162.0	8185.0	8329.0	8728.0	9688.0	10978.0
System Peak	7930.0	8202.0	8210.0	8234.0	8262.0	8285.0	8429.0	9728.0	10688.0	11978.0
Remaining Capacity	4649.0	4377.0	4369.0	4345.0	4317.0	4294.0	4150.0	3453.0	4193.0	4483.0
% of System Peak	58.6	53.4	53.2	52.8	52.3	51.8	49.2	35.5	39.2	37.4

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Yukon

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Fuelled										
Comb. Turbines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Int. Combustion	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	82.0	82.0
Total Generating Capacity	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**124.0**	**124.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	124.0	124.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	69.0	59.0	59.0	60.0	60.0	60.0	61.0	64.0	71.0	80.0
System Peak	69.0	59.0	59.0	60.0	60.0	60.0	61.0	64.0	71.0	80.0
Remaining Capacity	53.0	63.0	63.0	62.0	62.0	62.0	61.0	58.0	53.0	44.0
% of System Peak	76.8	106.8	106.8	103.3	103.3	103.3	100.0	90.6	74.6	55.0

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Fuelled										
Comb. Turbines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Int. Combustion	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	80.0	80.0	80.0	80.0	80.0	80.0	80.0	82.0	82.0	82.0
Total Generating Capacity	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**124.0**	**124.0**	**124.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	122.0	122.0	122.0	122.0	122.0	122.0	122.0	124.0	124.0	124.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	69.0	59.0	67.0	68.0	69.0	70.0	72.0	76.0	83.0	91.0
System Peak	69.0	59.0	67.0	68.0	69.0	70.0	72.0	76.0	83.0	91.0
Remaining Capacity	53.0	63.0	55.0	54.0	53.0	52.0	50.0	48.0	41.0	33.0
% of System Peak	76.8	106.8	82.1	79.4	76.8	74.3	69.4	63.2	49.4	36.3

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **Northwest Territories**

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Fuelled										
Comb. Turbines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Int. Combustion	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0
Total Generating Capacity	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	120.0	120.0	120.0	121.0	122.0	122.0	124.0	129.0	143.0	161.0
System Peak	120.0	120.0	120.0	121.0	122.0	122.0	124.0	129.0	143.0	161.0
Remaining Capacity	64.0	64.0	64.0	63.0	62.0	62.0	60.0	55.0	41.0	23.0
% of System Peak	53.3	53.3	53.3	52.1	50.8	50.8	48.4	42.6	28.7	14.3

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Fuelled										
Comb. Turbines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Int. Combustion	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	155.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0
Total Generating Capacity	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**184.0**	**198.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	184.0	198.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	120.0	120.0	122.0	124.0	125.0	128.0	130.0	138.0	155.0	172.0
System Peak	120.0	120.0	122.0	124.0	125.0	128.0	130.0	138.0	155.0	172.0
Remaining Capacity	64.0	64.0	62.0	60.0	59.0	56.0	54.0	46.0	29.0	26.0
% of System Peak	53.3	53.3	50.8	48.4	47.2	43.8	41.5	33.3	18.7	15.1

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **British Columbia, Yukon and Northwest Territories**

Low Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	600.0	600.0
Oil	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Gas	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0
Other	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0
Other Fossil Fuelled										
Comb. Turbines	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Int. Combustion	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	11114.0	11114.0	11114.0	11114.0	11114.0	11114.0	11114.0	11514.0	11516.0	11718.0
Total Generating Capacity	**12885.0**	**12885.0**	**12885.0**	**12885.0**	**12885.0**	**12885.0**	**12885.0**	**13285.0**	**13887.0**	**14089.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1100.0	1600.0
Capacity Available	12885.0	12885.0	12885.0	12885.0	12885.0	12885.0	12885.0	13285.0	14987.0	15689.0
Sales (Export)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	1000.0	1000.0	1000.0
Domestic Peak Demand	8019.0	8281.0	8333.0	8313.0	8285.0	8308.0	8437.0	8754.0	9545.0	10652.0
System Peak	8119.0	8381.0	8433.0	8413.0	8385.0	8408.0	8537.0	9754.0	10545.0	11652.0
Remaining Capacity	4766.0	4504.0	4452.0	4472.0	4500.0	4477.0	4348.0	3531.0	4442.0	4037.0
% of System Peak	58.7	53.7	52.8	53.2	53.7	53.2	50.9	36.2	42.1	34.6

High Case

Type of Capacity	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	600.0	600.0
Oil	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0	124.0
Gas	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0	1026.0
Other	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0	189.0
Other Fossil Fuelled										
Comb. Turbines	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Int. Combustion	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	260.0	274.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	11114.0	11114.0	11114.0	11114.0	11114.0	11114.0	11114.0	11718.0	11718.0	12798.0
Total Generating Capacity	**12885.0**	**12885.0**	**12885.0**	**12885.0**	**12885.0**	**12885.0**	**12885.0**	**13489.0**	**14089.0**	**15183.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1100.0	1600.0
Capacity Available	12885.0	12885.0	12885.0	12885.0	12885.0	12885.0	12885.0	13489.0	15189.0	16783.0
Sales (Export)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	1000.0	1000.0	1000.0
Domestic Peak Demand	8019.0	8281.0	8299.0	8326.0	8356.0	8383.0	8531.0	8942.0	9926.0	11241.0
System Peak	8119.0	8381.0	8399.0	8426.0	8456.0	8483.0	8631.0	9942.0	10926.0	12241.0
Remaining Capacity	4766.0	4504.0	4486.0	4459.0	4429.0	4402.0	4254.0	3547.0	4263.0	4542.0
% of System Peak	58.7	53.7	53.4	52.9	52.4	51.9	49.3	35.7	39.0	37.1

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-2
Energy Generation by Fuel Type - Canada, Provinces and Territories

Terawatt hours

Canada
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	30.2	38.6	25.5	21.8	19.3	28.4	25.6	27.7	38.1	44.6
-Sub-Bituminous	27.9	29.8	32.5	32.6	32.4	32.7	33.3	35.0	42.4	46.2
-Lignite	8.9	10.7	9.8	9.6	9.5	9.6	9.8	10.7	12.2	12.1
Oil Fired Steam										
-Light	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	5.1	7.2	5.3	4.6	5.4	7.6	8.3	8.4	11.5	11.7
Natural Gas Fired Steam	3.7	3.5	4.0	4.1	3.8	3.9	3.9	6.1	5.2	8.6
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.8	0.8
-Natural Gas	2.5	3.0	2.3	2.3	2.3	2.3	2.4	2.3	2.5	2.6
Internal Combustion										
-Diesel Oil	0.9	0.8	0.9	0.9	0.9	1.1	1.1	1.2	1.3	1.4
Nuclear	67.2	72.9	84.7	91.1	93.9	93.9	100.3	110.3	104.9	100.6
Hydroelectric	308.5	313.2	315.6	316.3	322.5	325.5	329.3	333.4	357.0	385.1
Other	2.0	2.0	2.2	2.3	2.7	3.0	3.6	4.4	5.8	6.2
Total Energy Generation	**457.0**	**482.0**	**482.7**	**485.7**	**492.8**	**508.1**	**517.6**	**539.5**	**581.6**	**620.0**
Tot. Domestic Consumption	**423.0**	**438.0**	**443.6**	**446.6**	**448.7**	**459.7**	**470.3**	**496.7**	**533.6**	**574.7**
Exports (Net)	**34.0**	**43.9**	**39.1**	**39.1**	**44.1**	**48.4**	**47.3**	**42.8**	**48.0**	**45.3**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	30.2	38.6	25.3	23.0	25.6	32.2	32.6	31.4	39.9	47.2
-Sub-Bituminous	27.9	29.8	33.5	33.9	35.3	37.1	39.3	43.0	52.8	59.2
-Lignite	8.9	10.7	9.9	10.0	10.2	10.3	10.5	11.8	12.6	14.5
Oil Fired Steam										
-Light	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	5.1	7.2	5.5	5.4	7.0	10.4	11.4	13.0	15.3	10.9
Natural Gas Fired Steam	3.7	3.5	4.4	4.8	4.5	4.4	4.5	7.9	7.7	8.8
Comb. Turbines										
-Light Oil	0.0	0.0	0.1	0.1	0.1	0.3	0.3	2.3	3.5	0.2
-Natural Gas	2.5	3.0	2.3	2.3	2.3	2.3	2.4	2.5	2.8	3.0
Internal Combustion										
-Diesel Oil	0.9	0.8	0.9	0.9	1.0	1.2	1.2	1.2	1.3	1.4
Nuclear	67.2	72.9	84.7	91.1	93.9	93.9	100.3	110.3	104.9	113.4
Hydroelectric	308.5	313.2	315.9	318.1	324.7	326.1	329.5	336.7	374.5	422.7
Other	2.0	2.0	2.2	2.3	2.7	3.0	3.6	4.4	5.8	6.2
Total Energy Generation	**457.0**	**482.0**	**484.6**	**491.9**	**507.1**	**521.1**	**535.3**	**564.4**	**621.0**	**687.5**
Tot. Domestic Consumption	**423.0**	**438.0**	**445.3**	**452.7**	**463.3**	**477.0**	**493.4**	**525.5**	**579.2**	**639.7**
Exports (Net)	**34.0**	**43.9**	**39.3**	**39.1**	**43.8**	**44.1**	**42.0**	**38.9**	**41.8**	**47.8**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours

Newfoundland
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	1278	2265.0	597.0	695.0	804.0	1022.0	1228.0	1684.0	2626.0	1313.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	29.0	29.0	29.0	33.0	38.0	50.0	113.0	93.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	98	53.0	60.0	59.0	58.0	64.0	68.0	71.0	85.0	58.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	39154	37772.0	41103.0	41103.0	41145.0	41144.0	41145.0	41145.0	41141.0	41145.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Energy Generation	40530.0	40090.0	41789.0	41886.0	42036.0	42263.0	42479.0	42950.0	43965.0	42609.0
Tot. Domestic Consumption	9834.0	9697.0	9952.0	10129.0	10335.0	10640.0	10889.0	11360.0	12375.0	13238.0
Interprovincial Transfers (net)	30696.0	30393.0	31837.0	31757.0	31701.0	31623.0	31590.0	31590.0	31590.0	29371.0
Exports (Net)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	1278.0	2265.0	962.0	1559.0	2359.0	2971.0	3941.0	5121.0	5128.0	475.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	42.0	57.0	100.0	230.0	228.0	1833.0	2522.0	0.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	98.0	53.0	69.0	73.0	82.0	89.0	77.0	57.0	56.0	56.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	39154.0	37772.0	41068.0	41103.0	41145.0	41135.0	41139.0	41145.0	41144.0	52445.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Energy Generation	40530.0	40090.0	42141.0	42792.0	43686.0	44425.0	45385.0	48156.0	48850.0	52976.0
Tot. Domestic Consumption	9834.0	9697.0	10551.0	11202.0	12096.0	12835.0	13795.0	16566.0	19625.0	20688.0
Interprovincial Transfers (net)	30696.0	30393.0	31590.0	31590.0	31590.0	31590.0	31590.0	31590.0	29225.0	32288.0
Exports (Net)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note: The numbers in this table have been rounded.

Gigawatt hours

Nova Scotia
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	5402.0	5944.0	5344.0	6073.0	6173.0	6853.0	7528.0	7723.0	8624.0	8796.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	827.0	885.0	1288.0	882.0	1018.0	1320.0	881.0	1163.0	1135.0	1432.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	1.0	10.0	3.0	12.0	22.0	48.0	13.0	40.0	45.0	94.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	1039.0	774.0	1102.0	1102.0	1102.0	1102.0	1102.0	1102.0	1102.0	1102.0
Other	135.0	130.0	135.0	138.0	140.0	143.0	146.0	280.0	280.0	280.0
Total Energy Generation	**7410.0**	**7749.0**	**7872.0**	**8207.0**	**8455.0**	**9466.0**	**9670.0**	**10308.0**	**11186.0**	**11704.0**
Tot. Domestic Consumption	**7950.0**	**8326.0**	**8432.0**	**8767.0**	**9015.0**	**9366.0**	**9570.0**	**10208.0**	**11086.0**	**11604.0**
Interprovincial Transfers (net)	**-540.0**	**-577.0**	**-560.0**	**-560.0**	**-560.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	5402.0	5944.0	5331.0	6065.0	6199.0	6883.0	7612.0	7843.0	9452.0	10396.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	827.0	885.0	1253.0	872.0	1058.0	1409.0	984.0	1415.0	1021.0	1055.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	1.0	10.0	2.0	11.0	26.0	60.0	22.0	77.0	40.0	56.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	1039.0	774.0	1102.0	1102.0	1102.0	1102.0	1102.0	1102.0	1102.0	1102.0
Other	135.0	130.0	135.0	138.0	140.0	143.0	146.0	280.0	280.0	280.0
Total Energy Generation	**7410.0**	**7749.0**	**7823.0**	**8188.0**	**8525.0**	**9597.0**	**9866.0**	**10717.0**	**11895.0**	**12889.0**
Tot. Domestic Consumption	**7950.0**	**8326.0**	**8383.0**	**8748.0**	**9085.0**	**9497.0**	**9766.0**	**10617.0**	**11795.0**	**12789.0**
Interprovincial Transfers (net)	**-540.0**	**-577.0**	**-560.0**	**-560.0**	**-560.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Prince Edward Island
Low Case

Gigawatt hours

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	10.0	50.0	51.0	57.0	56.0	55.0	54.0	55.0	50.0	53.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	1.0	1.0	8.0	10.0	8.0	9.0	10.0	8.0	10.0	11.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	1.0	5.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Energy Generation	**12.0**	**56.0**	**59.0**	**68.0**	**64.0**	**64.0**	**64.0**	**63.0**	**60.0**	**64.0**
Tot. Domestic Consumption	**607.0**	**647.0**	**669.0**	**688.0**	**709.0**	**729.0**	**749.0**	**799.0**	**866.0**	**932.0**
Interprovincial Transfers (net)	**-595.0**	**-591.0**	**-610.0**	**-620.0**	**-645.0**	**-665.0**	**-685.0**	**-736.0**	**-806.0**	**-868.0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	10.0	50.0	51.0	49.0	57.0	50.0	51.0	56.0	51.0	55.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	1.0	1.0	8.0	9.0	8.0	8.0	9.0	9.0	12.0	13.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	1.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Energy Generation	**12.0**	**56.0**	**59.0**	**58.0**	**65.0**	**58.0**	**60.0**	**65.0**	**63.0**	**68.0**
Tot. Domestic Consumption	**607.0**	**647.0**	**669.0**	**688.0**	**710.0**	**733.0**	**755.0**	**811.0**	**889.0**	**966.0**
Interprovincial Transfers (net)	**-595.0**	**-591.0**	**-610.0**	**-630.0**	**-645.0**	**-675.0**	**-695.0**	**-746.0**	**-826.0**	**-898.0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours

New Brunswick
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	945.0	1407.0	2137.0	2137.0	2137.0	2137.0	2137.0	6341.0	6341.0	6341.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	3.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	2616.0	3632.0	2757.0	2340.0	2782.0	4335.0	5248.0	4348.0	5393.0	6416.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	2.0	5.0	5.0	9.0	79.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	5227.0	5112.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0
Hydroelectric	3185.0	2219.0	2766.0	2771.0	2771.0	2771.0	2771.0	2771.0	2771.0	2771.0
Other	244.0	225.0	265.0	275.0	276.0	277.0	578.0	581.0	620.0	620.0
Total Energy Generation	**12222.0**	**12599.0**	**12782.0**	**12380.0**	**12823.0**	**14379.0**	**15596.0**	**18903.0**	**19991.0**	**21084.0**
Tot. Domestic Consumption	**11555.0**	**12377.0**	**13087.0**	**13676.0**	**14094.0**	**14830.0**	**15237.0**	**16095.0**	**17122.0**	**18154.0**
Interprovincial Transfers (net)	**-5925.0**	**-5651.0**	**-6830.0**	**-7820.0**	**-7795.0**	**-5735.0**	**-2185.0**	**636.0**	**706.0**	**768.0**
Exports (Net)	**6592.0**	**5873.0**	**6525.0**	**6524.0**	**6524.0**	**5284.0**	**2544.0**	**2172.0**	**2163.0**	**2162.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	945.0	1407.0	2137.0	2137.0	2137.0	2137.0	2137.0	6341.0	6341.0	7743.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	3.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	2616.0	3632.0	2651.0	2321.0	2728.0	5093.0	5540.0	4861.0	6359.0	6682.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	3.0	6.0	7.0	76.0	136.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Nuclear	5227.0	5112.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0
Hydroelectric	3185.0	2219.0	2766.0	2771.0	2771.0	2771.0	2771.0	2771.0	2771.0	2771.0
Other	244.0	225.0	265.0	275.0	276.0	277.0	578.0	581.0	620.0	620.0
Total Energy Generation	**12222.0**	**12599.0**	**12676.0**	**12361.0**	**12769.0**	**15138.0**	**15889.0**	**19418.0**	**21024.0**	**22809.0**
Tot. Domestic Consumption	**11555.0**	**12377.0**	**12981.0**	**13647.0**	**14240.0**	**15049.0**	**15520.0**	**16600.0**	**18135.0**	**19899.0**
Interprovincial Transfers (net)	**-5925.0**	**-5651.0**	**-6830.0**	**-7810.0**	**-7995.0**	**-4815.0**	**-2175.0**	**646.0**	**726.0**	**-52.0**
Exports (Net)	**6592.0**	**5873.0**	**6525.0**	**6524.0**	**6524.0**	**4904.0**	**2544.0**	**2172.0**	**2163.0**	**2962.0**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours

Atlantic
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	6347.0	7351.0	7481.0	8210.0	8310.0	8990.0	9665.0	14064.0	14965.0	15137.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	9.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	4731.0	6832.0	4693.0	3974.0	4660.0	6732.0	7411.0	7250.0	9204.0	9214.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	2.0	11.0	40.0	51.0	59.0	92.0	66.0	103.0	177.0	277.0
-Natural Gas										
Internal Combustion										
-Diesel Oil	101.0	58.0	60.0	60.0	58.0	64.0	68.0	71.0	85.0	58.0
Nuclear	5227.0	5112.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0
Hydroelectric	43378.0	40765.0	44971.0	44976.0	45018.0	45017.0	45018.0	45018.0	45014.0	45018.0
Other	379.0	355.0	400.0	413.0	416.0	420.0	724.0	861.0	900.0	900.0
Total Energy Generation	**60174.0**	**60494.0**	**62502.0**	**62541.0**	**63378.0**	**66172.0**	**67809.0**	**72224.0**	**75202.0**	**75461.0**
Tot. Domestic Consumption	**29946.0**	**31047.0**	**32140.0**	**33260.0**	**34153.0**	**35565.0**	**36445.0**	**38462.0**	**41449.0**	**43928.0**
Exports (Net)	**6592.0**	**5873.0**	**6525.0**	**6524.0**	**6524.0**	**5284.0**	**2544.0**	**2172.0**	**2163.0**	**2162.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	6347.0	7351.0	7468.0	8202.0	8336.0	9020.0	9749.0	14184.0	15793.0	18139.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	9.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	4731.0	6832.0	4917.0	4801.0	6202.0	9523.0	10516.0	11453.0	12559.0	8267.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	2.0	11.0	52.0	77.0	134.0	301.0	265.0	1926.0	2650.0	205.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	101.0	58.0	69.0	73.0	82.0	89.0	77.0	57.0	56.0	56.0
Nuclear	5227.0	5112.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0	4857.0
Hydroelectric	43378.0	40765.0	44936.0	44976.0	45018.0	45008.0	45012.0	45018.0	45017.0	56318.0
Other	379.0	355.0	400.0	413.0	416.0	420.0	724.0	861.0	900.0	900.0
Total Energy Generation	**60174.0**	**60494.0**	**62699.0**	**63399.0**	**65045.0**	**69218.0**	**71200.0**	**78356.0**	**81832.0**	**88742.0**
Tot. Domestic Consumption	**29946.0**	**31047.0**	**32584.0**	**34285.0**	**36131.0**	**38114.0**	**39836.0**	**44594.0**	**50444.0**	**54342.0**
Exports (Net)	**6592.0**	**5873.0**	**6525.0**	**6524.0**	**6524.0**	**4904.0**	**2544.0**	**2172.0**	**2163.0**	**2962.0**

Note: The numbers in this table have been rounded.

Gigawatt hours

Quebec
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	29.0	1.0	30.0	30.0	60.0	60.0	62.0	411.0	1373.0	1330.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	590.0	507.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	201.0	205.0	240.0	240.0	240.0	440.0	440.0	440.0	440.0	440.0
Nuclear	3792.0	4660.0	5101.0	5101.0	5101.0	5101.0	5101.0	5101.0	5101.0	5101.0
Hydroelectric[a]	144901.0	152086.0	150667.0	151037.0	153874.0	156099.0	156470.0	158102.0	172162.0	191467.0
Other	2.0	0.0	15.0	20.0	40.0	40.0	40.0	50.0	50.0	50.0
Total Energy Generation	**148926.0**	**156952.0**	**156053.0**	**156428.0**	**159315.0**	**161740.0**	**162113.0**	**164113.0**	**179716.0**	**198895.0**
Tot. Domestic Consumption	**152626.0**	**158196.0**	**157746.0**	**157841.0**	**158402.0**	**162059.0**	**166021.0**	**176632.0**	**189834.0**	**202934.0**
Interprovincial Transfers (net)	**-16340.0**	**-17645.0**	**-18114.0**	**-17834.0**	**-17778.0**	**-24400.0**	**-27897.0**	**-30667.0**	**-30667.0**	**-28448.0**
Exports (Net)	**12640.0**	**16401.0**	**16421.0**	**16421.0**	**18691.0**	**24081.0**	**23989.0**	**18148.0**	**20549.0**	**24409.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	29.0	1.0	30.0	30.0	60.0	60.0	61.0	802.0	1795.0	1247.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	327.0	843.0	0.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	201.0	205.0	240.0	240.0	240.0	440.0	440.0	440.0	440.0	440.0
Nuclear	3792.0	4660.0	5101.0	5101.0	5101.0	5101.0	5101.0	5101.0	5101.0	5101.0
Hydroelectric	144901.0	152086.0	150909.0	152632.0	155881.0	156168.0	156470.0	160849.0	184684.0	213743.0
Other	2.0	0.0	15.0	20.0	40.0	40.0	40.0	50.0	50.0	50.0
Total Energy Generation	**148926.0**	**156952.0**	**156295.0**	**158023.0**	**161322.0**	**161809.0**	**162112.0**	**167569.0**	**192913.0**	**220581.0**
Tot. Domestic Consumption	**152626.0**	**158196.0**	**157741.0**	**159269.0**	**162398.0**	**166005.0**	**171130.0**	**183298.0**	**201836.0**	**223917.0**
Interprovincial Transfers (net)	**-16340.0**	**-17645.0**	**-17867.0**	**-17667.0**	**-19767.0**	**-25277.0**	**-27897.0**	**-30667.0**	**-28302.0**	**-30515.0**
Exports (Net)	**12640.0**	**16401.0**	**16421.0**	**16421.0**	**18691.0**	**21081.0**	**18879.0**	**14938.0**	**19379.0**	**27179.0**

Note: The numbers in this table have been rounded.
[a] Hydro generation includes losses attributable to pumped storage hydro plants.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours

Ontario
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	23350.0	30775.0	17990.0	13584.0	11028.0	19410.0	15959.0	13591.0	23117.0	29468.0
-Sub-Bituminous	0.0	0.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0
-Lignite	1052.0	1393.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1212.0
Oil Fired Steam										
-Light	42.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	14.0	15.0	125.0	175.0	240.0	337.0	337.0	337.0	480.0	714.0
Natural Gas Fired Steam	596.0	562.0	985.0	1120.0	1185.0	1250.0	1315.0	1562.0	1659.0	1700.0
Comb. Turbines										
-Light Oil	11.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	692.0	969.0	867.0	867.0	867.0	867.0	964.0	964.0	1060.0	1060.0
Internal Combustion										
-Diesel Oil	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	58213.0	63116.0	74707.0	81113.0	83909.0	83909.0	90315.0	100329.0	94949.0	90642.0
Hydroelectric	41206.0	34604.0	39328.0	39528.0	39528.0	39528.0	39628.0	39628.0	40988.0	42114.0
Other	90.0	91.0	210.0	245.0	300.0	345.0	410.0	574.0	750.0	925.0
Total Energy Generation	**125267.0**	**131582.0**	**137612.0**	**140032.0**	**140457.0**	**149046.0**	**152328.0**	**160385.0**	**166403.0**	**170235.0**
Tot. Domestic Consumption	**127031.0**	**132174.0**	**135385.0**	**137005.0**	**138230.0**	**142819.0**	**147101.0**	**155158.0**	**162476.0**	**171778.0**
Interprovincial Transfers (net)	**-8027.0**	**-6906.0**	**-5723.0**	**-4923.0**	**-5723.0**	**-1723.0**	**-1723.0**	**-1723.0**	**-3123.0**	**-3123.0**
Exports (Net)	**6263.0**	**6314.0**	**7950.0**	**7950.0**	**7950.0**	**7950.0**	**6950.0**	**6950.0**	**7050.0**	**1580.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	23350.0	30775.0	17784.0	14789.0	17261.0	23220.0	22821.0	17231.0	24114.0	29054.0
-Sub-Bituminous	0.0	0.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0
-Lignite	1052.0	1393.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1050.0	1290.0
Oil Fired Steam										
-Light	42.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	14.0	15.0	125.0	175.0	240.0	337.0	337.0	337.0	480.0	978.0
Natural Gas Fired Steam	596.0	562.0	985.0	1120.0	1185.0	1250.0	1315.0	1562.0	1659.0	1700.0
Comb. Turbines										
-Light Oil	11.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	692.0	969.0	867.0	867.0	867.0	867.0	964.0	964.0	1060.0	1060.0
Internal Combustion										
-Diesel Oil	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	58213.0	63116.0	74707.0	81113.0	83909.0	83909.0	90315.0	100329.0	94949.0	103453.0
Hydroelectric	41206.0	34604.0	39328.0	39528.0	39528.0	39528.0	39628.0	40230.0	42014.0	42114.0
Other	90.0	91.0	210.0	245.0	300.0	345.0	410.0	574.0	750.0	925.0
Total Energy Generation	**125267.0**	**131582.0**	**137406.0**	**141237.0**	**146690.0**	**152856.0**	**159190.0**	**164627.0**	**168476.0**	**182974.0**
Tot. Domestic Consumption	**127031.0**	**132174.0**	**135179.0**	**138210.0**	**142163.0**	**147629.0**	**153963.0**	**159400.0**	**168749.0**	**184947.0**
Interprovincial Transfers (net)	**-8027.0**	**-6906.0**	**-5723.0**	**-4923.0**	**-3423.0**	**-1723.0**	**-1723.0**	**-1723.0**	**-3123.0**	**-3123.0**
Exports (Net)	**6263.0**	**6314.0**	**7950.0**	**7950.0**	**7950.0**	**6950.0**	**6950.0**	**6950.0**	**2850.0**	**1150.0**

Note: The numbers in this table have been rounded.

Gigawatt hours

Manitoba
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	95.0	512.0	0.0	0.0	0.0	0.0	0.0	0.0	141.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	2.0	2.0	20.0	20.0	20.0	15.0	15.0	15.0	15.0	15.0
Natural Gas Fired Steam	8.0	8.0	10.0	10.0	10.0	20.0	20.0	20.0	20.0	20.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	53.0	32.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	23840.0	19311.0	17799.0	17931.0	21239.0	22025.0	25256.0	27713.0	30432.0	34522.0
Other	61.0	56.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Total Energy Generation	**24059.0**	**19921.0**	**17879.0**	**18011.0**	**21319.0**	**22110.0**	**25341.0**	**27798.0**	**30658.0**	**34607.0**
Tot. Domestic Consumption	**16222.0**	**15880.0**	**16900.0**	**17032.0**	**17140.0**	**17731.0**	**17962.0**	**18994.0**	**20784.0**	**23003.0**
Interprovincial Transfers (net)	**859.0**	**1092.0**	**0.0**	**0.0**	**800.0**	**800.0**	**800.0**	**800.0**	**2200.0**	**2200.0**
Exports (Net)	**6978.0**	**2949.0**	**979.0**	**979.0**	**3379.0**	**3579.0**	**6579.0**	**8004.0**	**7674.0**	**9404.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	95.0	512.0	0.0	0.0	88.0	0.0	0.0	0.0	234.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	2.0	2.0	20.0	20.0	20.0	15.0	15.0	15.0	15.0	15.0
Natural Gas Fired Steam	8.0	8.0	10.0	10.0	10.0	20.0	20.0	20.0	20.0	20.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	53.0	32.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	23840.0	19311.0	17828.0	18058.0	21338.0	22487.0	25431.0	27653.0	31578.0	34676.0
Other	61.0	56.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
Total Energy Generation	**24059.0**	**19921.0**	**17908.0**	**18138.0**	**21506.0**	**22572.0**	**25516.0**	**27738.0**	**31897.0**	**34761.0**
Tot. Domestic Consumption	**16222.0**	**15880.0**	**16929.0**	**17159.0**	**17327.0**	**17793.0**	**18137.0**	**19334.0**	**21493.0**	**23857.0**
Interprovincial Transfers (net)	**859.0**	**1092.0**	**0.0**	**0.0**	**800.0**	**800.0**	**800.0**	**800.0**	**2200.0**	**2200.0**
Exports (Net)	**6978.0**	**2949.0**	**979.0**	**979.0**	**3379.0**	**3979.0**	**6579.0**	**7604.0**	**8204.0**	**8704.0**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours

Saskatchewan
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
-Lignite	7728.0	8818.0	8764.0	8624.0	8502.0	8634.0	8825.0	9705.0	11071.0	10923.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	5.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	10.0	10.0
Natural Gas Fired Steam	244.0	253.0	248.0	243.0	244.0	248.0	255.0	247.0	313.0	307.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	5.0	0.0	33.0	25.0	20.0	26.0	34.0	11.0	66.0	59.0
Internal Combustion										
-Diesel Oil	11.0	26.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	3767.0	3188.0	3776.0	3776.0	3776.0	3776.0	3776.0	3776.0	3776.0	5378.0
Other	139.0	150.0	150.0	150.0	150.0	160.0	160.0	180.0	200.0	200.0
Total Energy Generation	**11899.0**	**12440.0**	**13041.0**	**12888.0**	**12767.0**	**12919.0**	**13125.0**	**13994.0**	**15501.0**	**16942.0**
Tot. Domestic Consumption	**11947.0**	**12451.0**	**12928.0**	**12855.0**	**12734.0**	**12886.0**	**13062.0**	**13851.0**	**15358.0**	**16799.0**
Interprovincial Transfers (net)	**-139.0**	**-45.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**
Exports (Net)	**91.0**	**34.0**	**114.0**	**34.0**	**34.0**	**34.0**	**64.0**	**144.0**	**144.0**	**144.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
-Lignite	7728.0	8818.0	8876.0	8960.0	9074.0	9273.0	9535.0	10779.0	11364.0	13171.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	5.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	10.0	10.0
Natural Gas Fired Steam	244.0	253.0	252.0	255.0	265.0	274.0	290.0	279.0	332.0	337.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	5.0	0.0	37.0	39.0	44.0	53.0	69.0	51.0	87.0	115.0
Internal Combustion										
-Diesel Oil	11.0	26.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	3767.0	3188.0	3776.0	3776.0	3776.0	3776.0	3776.0	3776.0	5378.0	5378.0
Other	139.0	150.0	150.0	150.0	150.0	160.0	160.0	180.0	200.0	200.0
Total Energy Generation	**11899.0**	**12440.0**	**13161.0**	**13250.0**	**13384.0**	**13611.0**	**13905.0**	**15140.0**	**17436.0**	**19276.0**
Tot. Domestic Consumption	**11947.0**	**12451.0**	**13048.0**	**13217.0**	**13351.0**	**13578.0**	**13842.0**	**14997.0**	**17293.0**	**19133.0**
Interprovincial Transfers (net)	**-139.0**	**-45.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**
Exports (net)	**91.0**	**34.0**	**114.0**	**34.0**	**34.0**	**34.0**	**64.0**	**144.0**	**144.0**	**144.0**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours

Alberta
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	481.0	514.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	27881.0	29826.0	30022.0	30096.0	29977.0	30231.0	30875.0	32499.0	35717.0	39496.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	23.0	20.0	20.0	20.0	10.0	5.0	0.0	0.0	0.0	0.0
-Heavy	86.0	80.0	70.0	50.0	40.0	35.0	20.0	20.0	20.0	20.0
Natural Gas Fired Steam	2297.0	2120.0	2061.0	2091.0	1686.0	1622.0	1586.0	1930.0	2455.0	3651.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	1785.0	1997.0	1300.0	1300.0	1300.0	1300.0	1300.0	1300.0	1300.0	1403.0
Internal Combustion										
-Diesel Oil	82.0	80.0	245.0	245.0	245.0	245.0	245.0	245.0	245.0	250.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	1816.0	1494.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0
Other	406.0	395.0	425.0	475.0	710.0	906.0	1083.0	1528.0	2505.0	2812.0
Total Energy Generation	**34857.0**	**36526.0**	**35779.0**	**35913.0**	**35604.0**	**35980.0**	**36745.0**	**39158.0**	**43878.0**	**49268.0**
Tot. Domestic Consumption	**34800.0**	**36344.0**	**35580.0**	**35714.0**	**35205.0**	**34981.0**	**35246.0**	**37259.0**	**41979.0**	**47269.0**
Interprovincial Transfers (net)	**60.0**	**184.0**	**200.0**	**200.0**	**400.0**	**1000.0**	**1500.0**	**1900.0**	**1900.0**	**2000.0**
Exports (Net)	**-3.0**	**-2.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	481.0	514.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	27881.0	29826.0	31060.0	31420.0	32878.0	34605.0	36785.0	40504.0	46099.0	52519.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	23.0	20.0	20.0	20.0	10.0	5.0	0.0	0.0	0.0	0.0
-Heavy	86.0	80.0	70.0	50.0	40.0	35.0	20.0	20.0	20.0	20.0
Natural Gas Fired Steam	2297.0	2120.0	2476.0	2674.0	2259.0	2023.0	1896.0	3084.0	4433.0	4051.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	1785.0	1997.0	1320.0	1336.0	1300.0	1300.0	1300.0	1359.0	1564.0	1691.0
Internal Combustion										
-Diesel Oil	82.0	80.0	245.0	245.0	245.0	245.0	245.0	246.0	252.0	249.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	1816.0	1494.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0
Other	406.0	395.0	425.0	475.0	710.0	906.0	1083.0	1528.0	2505.0	2812.0
Total Energy Generation	**34857.0**	**36526.0**	**37252.0**	**37856.0**	**39078.0**	**40755.0**	**42965.0**	**48377.0**	**56509.0**	**62978.0**
Tot. Domestic Consumption	**34800.0**	**36344.0**	**37053.0**	**37657.0**	**38679.0**	**39756.0**	**41466.0**	**46478.0**	**55410.0**	**60979.0**
Interprovincial Transfers (net)	**60.0**	**184.0**	**200.0**	**200.0**	**400.0**	**1000.0**	**1500.0**	**1900.0**	**1100.0**	**2000.0**
Exports (Net)	**-3.0**	**-2.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**	**-1.0**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours

Prairies
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	481.0	514.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	27881.0	29826.0	30087.0	30161.0	30042.0	30296.0	30940.0	32564.0	35782.0	39561.0
-Lignite	7823.0	9330.0	8764.0	8624.0	8502.0	8634.0	8825.0	9705.0	11212.0	10923.0
Oil Fired Steam										
-Light	23.0	20.0	20.0	20.0	10.0	5.0	0.0	0.0	0.0	0.0
-Heavy	93.0	87.0	95.0	75.0	70.0	60.0	45.0	45.0	45.0	45.0
Natural Gas Fired Steam	2549.0	2381.0	2319.0	2344.0	1940.0	1890.0	1861.0	2197.0	2788.0	3978.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	1790.0	1997.0	1333.0	1325.0	1320.0	1326.0	1334.0	1311.0	1366.0	1462.0
Internal Combustion										
-Diesel Oil	146.0	138.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	255.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	29423.0	23993.0	23211.0	23343.0	26651.0	27437.0	30668.0	33125.0	35844.0	41536.0
Other	606.0	601.0	620.0	670.0	905.0	1111.0	1288.0	1753.0	2750.0	3057.0
Total Energy Generation	**70815.0**	**68887.0**	**66699.0**	**66812.0**	**69690.0**	**71009.0**	**75211.0**	**80950.0**	**90037.0**	**100817.0**
Tot. Domestic Consumption	**62969.0**	**64675.0**	**65408.0**	**65601.0**	**65079.0**	**65598.0**	**66270.0**	**70104.0**	**78121.0**	**87071.0**
Exports (Net)	**7066.0**	**2981.0**	**1092.0**	**1012.0**	**3412.0**	**3612.0**	**6642.0**	**8147.0**	**7817.0**	**9547.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	481.0	514.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	27881.0	29826.0	31125.0	31485.0	32943.0	34670.0	36850.0	40569.0	46164.0	52584.0
-Lignite	7823.0	9330.0	8876.0	8960.0	9162.0	9273.0	9535.0	10779.0	11598.0	13171.0
Oil Fired Steam										
-Light	23.0	20.0	20.0	20.0	10.0	5.0	0.0	0.0	0.0	0.0
-Heavy	93.0	87.0	95.0	75.0	70.0	60.0	45.0	45.0	45.0	45.0
Natural Gas Fired Steam	2549.0	2381.0	2738.0	2939.0	2534.0	2317.0	2206.0	3383.0	4785.0	4408.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	1790.0	1997.0	1357.0	1375.0	1344.0	1353.0	1369.0	1410.0	1651.0	1806.0
Internal Combustion										
-Diesel Oil	146.0	138.0	250.0	250.0	250.0	250.0	250.0	251.0	257.0	254.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	29423.0	23993.0	23240.0	23470.0	26750.0	27899.0	30843.0	33065.0	38592.0	41690.0
Other	606.0	601.0	620.0	670.0	905.0	1111.0	1288.0	1753.0	2750.0	3057.0
Total Energy Generation	**70815.0**	**68887.0**	**68321.0**	**69244.0**	**73968.0**	**76938.0**	**82386.0**	**91255.0**	**105842.0**	**117015.0**
Tot. Domestic Consumption	**62969.0**	**64675.0**	**67030.0**	**68033.0**	**69357.0**	**71127.0**	**73445.0**	**80809.0**	**94196.0**	**103969.0**
Exports (Net)	**7066.0**	**2981.0**	**1092.0**	**1012.0**	**3412.0**	**4012.0**	**6642.0**	**7747.0**	**8347.0**	**8847.0**

Note: The numbers in this table have been rounded.

Gigawatt hours

British Columbia
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4205.0	4205.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	259.0	274.0	350.0	350.0	400.0	400.0	400.0	400.0	400.0	400.0
Natural Gas Fired Steam	567.0	580.0	694.0	668.0	676.0	763.0	742.0	2330.0	783.0	2964.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0
Internal Combustion										
-Diesel Oil	192.0	200.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	90.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric[a]	48935.0	61052.0	56841.0	56866.0	56866.0	56866.0	56866.0	56866.0	62367.0	64267.0
Other	908.0	961.0	960.0	975.0	1010.0	1055.0	1100.0	1185.0	1300.0	1300.0
Total Energy Generation	**50861.0**	**63067.0**	**58915.0**	**58929.0**	**59022.0**	**59154.0**	**59178.0**	**60851.0**	**69125.0**	**73315.0**
Tot. Domestic Consumption	**49494.0**	**50934.0**	**52015.0**	**51929.0**	**51872.0**	**52704.0**	**53478.0**	**55351.0**	**60625.0**	**67715.0**
Interprovincial Transfers (net)	**-62.0**	**-189.0**	**-200.0**	**-200.0**	**-400.0**	**-1000.0**	**-1500.0**	**-1900.0**	**-1900.0**	**-2000.0**
Exports (Net)	**1429.0**	**12322.0**	**7100.0**	**7200.0**	**7550.0**	**7450.0**	**7200.0**	**7400.0**	**10400.0**	**7600.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4205.0	4205.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	259.0	274.0	350.0	350.0	400.0	400.0	400.0	400.0	400.0	400.0
Natural Gas Fired Steam	567.0	580.0	684.0	692.0	734.0	855.0	966.0	2960.0	1278.0	2677.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	37.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	35.0
Internal Combustion										
-Diesel Oil	192.0	200.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	86.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric[a]	48935.0	61052.0	56841.0	56866.0	56866.0	56866.0	56866.0	56866.0	63457.0	68078.0
Other	908.0	961.0	960.0	975.0	1010.0	1055.0	1100.0	1185.0	1300.0	1300.0
Total Energy Generation	**50861.0**	**63067.0**	**58905.0**	**58953.0**	**59080.0**	**59246.0**	**59402.0**	**61494.0**	**70710.0**	**76818.0**
Tot. Domestic Consumption	**49494.0**	**50934.0**	**51765.0**	**51943.0**	**52210.0**	**53046.0**	**53922.0**	**56314.0**	**62720.0**	**71128.0**
Interprovincial Transfers (net)	**-62.0**	**-189.0**	**-200.0**	**-200.0**	**-400.0**	**-1000.0**	**-1500.0**	**-1900.0**	**-1100.0**	**-2000.0**
Exports (Net)	**1429.0**	**12322.0**	**7340.0**	**7210.0**	**7270.0**	**7200.0**	**6980.0**	**7080.0**	**9090.0**	**7690.0**

Notes: The numbers in this table have been rounded.
[a] Includes recall of downstream benefits from Columbia River Treaty.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours

Yukon
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	22.0	23.0	28.0	28.0	28.0	29.0	29.0	30.0	37.0	48.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	322.0	409.0	284.0	286.0	288.0	288.0	293.0	306.0	337.0	375.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Energy Generation	**344.0**	**432.0**	**312.0**	**314.0**	**316.0**	**317.0**	**322.0**	**336.0**	**374.0**	**423.0**
Tot. Domestic Consumption	**344.0**	**432.0**	**312.0**	**314.0**	**316.0**	**317.0**	**322.0**	**336.0**	**374.0**	**423.0**
Interprovincial Transfers (net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	22.0	23.0	33.0	34.0	35.0	36.0	38.0	40.0	52.0	76.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	322.0	409.0	320.0	324.0	328.0	333.0	338.0	357.0	382.0	403.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Energy Generation	**344.0**	**432.0**	**353.0**	**358.0**	**363.0**	**369.0**	**376.0**	**397.0**	**434.0**	**479.0**
Tot. Domestic Consumption	**344.0**	**432.0**	**353.0**	**358.0**	**363.0**	**369.0**	**376.0**	**397.0**	**434.0**	**479.0**
Interprovincial Transfers (net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Note: The numbers in this table have been rounded.

Gigawatt hours

Northwest Territories
Low Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	67.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Internal Combustion										
-Diesel Oil	205.0	190.0	247.0	253.0	255.0	257.0	268.0	297.0	372.0	470.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	346.0	294.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Energy Generation	**618.0**	**554.0**	**624.0**	**630.0**	**632.0**	**634.0**	**645.0**	**674.0**	**749.0**	**847.0**
Tot. Domestic Consumption	**618.0**	**554.0**	**624.0**	**630.0**	**632.0**	**634.0**	**645.0**	**674.0**	**749.0**	**847.0**
Interprovincial Transfers (net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

High Case

Type of Generation	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	67.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Internal Combustion										
-Diesel Oil	205.0	190.0	257.0	268.0	275.0	288.0	302.0	343.0	438.0	529.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	346.0	294.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Energy Generation	**618.0**	**554.0**	**634.0**	**645.0**	**652.0**	**665.0**	**679.0**	**720.0**	**815.0**	**906.0**
Tot. Domestic Consumption	**618.0**	**554.0**	**634.0**	**645.0**	**652.0**	**665.0**	**679.0**	**720.0**	**815.0**	**906.0**
Interprovincial Transfers (net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours — **British Columbia, Yukon and Northwest Territories**

Low Case

Type of Generation	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4205.0	4205.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	259.0	274.0	350.0	350.0	400.0	400.0	400.0	400.0	400.0	400.0
Natural Gas Fired Steam	567.0	580.0	694.0	668.0	676.0	763.0	742.0	2330.0	783.0	2964.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.0
-Natural Gas	67.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	113.0
Internal Combustion										
-Diesel Oil	419.0	413.0	345.0	351.0	353.0	356.0	367.0	397.0	479.0	608.0
Nuclear										
Hydroelectric	49603.0	61755.0	57432.0	57459.0	57461.0	57461.0	57466.0	57479.0	63011.0	64949.0
Other	908.0	961.0	960.0	975.0	1010.0	1055.0	1100.0	1185.0	1300.0	1300.0
Total Energy Generation	**51823.0**	**64053.0**	**59851.0**	**59873.0**	**59970.0**	**60105.0**	**60145.0**	**61861.0**	**70248.0**	**74585.0**
Tot. Domestic Consumption	**50456.0**	**51920.0**	**52951.0**	**52873.0**	**52820.0**	**53655.0**	**54445.0**	**56361.0**	**61748.0**	**68985.0**
Exports (Net)	**1429.0**	**12322.0**	**7100.0**	**7200.0**	**7550.0**	**7450.0**	**7200.0**	**7400.0**	**10400.0**	**7600.0**

High Case

Type of Generation	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1995**	**2000**	**2005**
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4205.0	4205.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	259.0	274.0	350.0	350.0	400.0	400.0	400.0	400.0	400.0	400.0
Natural Gas Fired Steam	567.0	580.0	684.0	692.0	734.0	855.0	966.0	2960.0	1278.0	2677.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	37.0
-Natural Gas	67.0	67.0	70.0	70.0	70.0	70.0	70.0	77.0	70.0	105.0
Internal Combustion										
-Diesel Oil	419.0	413.0	360.0	372.0	380.0	394.0	410.0	453.0	560.0	691.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	49603.0	61755.0	57468.0	57497.0	57501.0	57506.0	57511.0	57530.0	64146.0	68788.0
Other	908.0	961.0	960.0	975.0	1010.0	1055.0	1100.0	1185.0	1300.0	1300.0
Total Energy Generation	**51823.0**	**64050.0**	**59892.0**	**59956.0**	**60095.0**	**60280.0**	**60457.0**	**62611.0**	**71959.0**	**78203.0**
Tot. Domestic Consumption	**50456.0**	**51920.0**	**52752.0**	**52946.0**	**53225.0**	**54080.0**	**54977.0**	**57431.0**	**63969.0**	**72513.0**
Exports (Net)	**1429.0**	**12322.0**	**7340.0**	**7210.0**	**7270.0**	**7200.0**	**6980.0**	**7080.0**	**9090.0**	**7690.0**

Note: The numbers in this table have been rounded.

Table A5-3
Fuel Requirements for Electricity Generation - Canada

Petajoules

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal[a]										
-Bituminous	334	412	270	231	206	300	272	298	406	473
-Sub-Bituminous	344	358	371	372	370	373	381	399	436	480
-Lignite	118	140	121	115	109	107	109	118	136	134
-Total Coal	796	909	762	718	686	780	761	816	978	1087
Oil[a]										
-Light	1	1	0	0	0	0	0	0	0	1
-Heavy	49	71	53	47	56	79	86	90	123	125
-Diesel	10	10	10	10	11	13	13	14	15	16
-Total Oil	60	82	64	58	67	92	99	104	138	142
Natural Gas[a]	58	66	67	71	70	73	75	103	94	138
Uranium[b]	814	882	1024	1102	1136	1136	1213	1335	1269	1217
Hydroelectric[c]	1111	1128	1136	1139	1161	1172	1185	1200	1266	1360
Other [d]	18	19	22	24	28	31	38	47	61	66
Total Fuel Requirements	**2856**	**3086**	**3075**	**3112**	**3148**	**3284**	**3372**	**3604**	**3806**	**4009**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Coal[a]										
-Bituminous	334	412	268	244	271	340	343	337	425	503
-Sub-Bituminous	344	358	383	387	404	424	449	492	565	630
-Lignite	118	140	122	119	117	114	116	130	141	160
-Total Coal	796	909	773	750	792	877	909	958	1131	1292
Oil[a]										
-Light	1	1	0	0	0	0	0	0	1	2
-Heavy	49	71	56	56	73	109	120	140	164	116
-Diesel	10	10	10	11	11	14	14	14	16	17
-Total Oil	60	82	66	67	85	123	134	154	181	135
Natural Gas[a]	58	66	71	78	78	79	83	127	128	144
Uranium[b]	814	882	1024	1102	1136	1136	1213	1335	1269	1372
Hydroelectric[c]	1111	1128	1137	1145	1169	1174	1186	1212	1325	1495
Other [d]	18	19	22	24	28	31	38	47	61	66
Total Fuel Requirements	**2856**	**3086**	**3094**	**3166**	**3287**	**3420**	**3562**	**3833**	**4095**	**4503**

Notes: The numbers in this table have been rounded.

[a] Converted to petajoules from thermal generation based on plant specific factors.

[b] Converted to petajoules from nuclear generation based on a rate of 12.1 PJ/TW.h.

[c] Converted to petajoules from hydro generation based on a rate of 3.6 PJ/TW.h.

[d] Other includes electricity production from forest wastes, industrial fuels such as blast furnace gas, as well as minor sources of production such as wind, solar, etc.

Table A5-4
Net Electricity Exports and Transfers
Canada and Provinces (GWh) [a]

Historical

	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
Newfoundland	83	81	81	84	260	6401	13888	22228	29597	32106
Prince Edward Island	0	0	0	0	0	0	0	0	0	0
Nova Scotia	73	114	-269	-195	-7	-143	-178	-156	-199	-334
New Brunswick	207	352	771	920	1063	790	463	-873	-2035	-1015
Quebec	5094	4660	4497	6148	5500	260	-1793	-7321	-13824	-16544
Ontario	-4728	-4784	-3927	-5632	-4411	-4059	-4260	-6158	-10640	-8724
Manitoba	-187	-503	-469	-319	424	899	1405	2898	2893	1899
Saskatchewan	393	444	443	777	518	425	372	90	-97	37
Alberta	0	-1	33	155	151	143	3	-18	-146	-316
British Columbia	-1123	-779	420	464	130	889	4727	2267	1853	2104
Canada	**-344**	**-611**	**1768**	**2513**	**3375**	**-653**	**917**	**-9115**	**-21996**	**-22559**

Historical

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Newfoundland	33350	37024	35290	37829	35941	35779	31229	36012	31836	30696
Prince Edward Island	-67	-269	-361	-388	-480	-478	-520	-550	-585	-595
Nova Scotia	-376	-224	-351	54	-192	-83	616	-32	-169	-540
New Brunswick	248	-550	983	485	147	-95	2408	1881	886	667
Quebec	-18681	-23876	-18859	-20336	-17481	-17923	-11714	-13132	-7733	-3700
Ontario	-2709	663	4784	3775	3367	3988	5570	2223	-677	-1764
Manitoba	302	4244	6360	5541	4902	6516	7318	6246	6864	7837
Saskatchewan	208	38	-474	-624	-248	-390	-402	-272	-211	-48
Alberta	252	50	286	26	91	-259	-122	-43	137	57
British Columbia	4741	2412	1920	631	7828	4307	2499	6759	9974	1367
Canada	**-15639**	**-17019**	**-5000**	**-10502**	**-1394**	**-3856**	**5557**	**3662**	**9240**	**4416**

Notes: The numbers in this table have been rounded.
[a] Net Exports and Transfers represent the arithmetic sum of all inflows and outflows where inflows are negative and outflows are positive. Here net outflows are shown as positive.

Table A5-4 (Continued)
Net Electricity Exports and Transfers
Canada and Provinces (GWh) [a]

Projected
Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Newfoundland	30393	31837	31757	31701	31623	31590	31590	31590	29371
Prince Edward Island	-591	-610	-620	-645	-665	-685	-736	-806	-868
Nova Scotia	-577	-560	-560	-560	100	100	100	100	100
New Brunswick	222	-305	-1296	-1271	-451	359	2808	2869	2930
Quebec	-1244	-1693	-1413	913	-319	-3908	-12519	-10118	-4039
Ontario	-592	2227	3027	2227	6227	5227	5227	3927	-1543
Manitoba	4041	979	979	4179	4379	7379	8804	9874	11604
Saskatchewan	-11	113	33	33	33	63	143	143	143
Alberta	182	199	199	399	999	1499	1899	1899	1999
British Columbia	12133	6900	7000	7150	6450	5700	5500	3000	-1800
Canada	**43956**	**39087**	**39106**	**44126**	**48376**	**47324**	**42816**	**42478**	**37897**

Projected
High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Newfoundland	30393	31590	31590	31590	31590	31590	31590	29225	32288
Prince Edward Island	-591	-610	-630	-645	-675	-695	-746	-826	-898
Nova Scotia	-577	-560	560	-560	100	100	100	100	100
New Brunswick	222	-305	-1286	-1471	89	369	2818	2889	2910
Quebec	-1244	-1446	-1246	-1076	-4196	-9018	-15729	-8923	-3336
Ontario	-592	2227	3027	4527	5227	5227	5227	-273	-1973
Manitoba	4041	979	979	4179	4779	7379	8404	10404	10904
Saskatchewan	-11	113	33	33	33	63	143	143	143
Alberta	182	199	199	399	999	1499	1899	1099	1999
British Columbia	12133	7140	7010	6870	6200	5480	5180	1690	-1710
Canada	**43956**	**39327**	**40236**	**43846**	**44146**	**41994**	**38886**	**35528**	**40427**

Notes: The numbers in this table have been rounded.
[a] Net Exports and Transfers represent the arithmetic sum of all inflows and outflows where inflows are negative and outflows are positive. Here net outflows are shown as positive.

Table A5-5
Net Electricity Exports - Canada and Provinces

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
					Low Case					
					Gigawatt hours					
New Brunswick	6592	5873	6525	6524	6524	5284	2544	2172	2163	2162
Quebec	12640	16401	16421	16421	18691	24081	23989	18148	20549	24409
Ontario	6263	6314	7950	7950	7950	7950	6950	6950	7050	1580
Manitoba	6978	2949	979	979	3379	3579	6579	8004	7674	9404
Saskatchewan	91	34	114	34	34	34	64	144	144	144
Alberta	-3	-2	-1	-1	-1	-1	-1	-1	-1	-1
British Columbia	1429	12322	7100	7200	7550	7450	7200	7400	10400	7600
Canada	**33990**	**43891**	**39088**	**39107**	**44127**	**48377**	**47325**	**42817**	**47979**	**45298**
					Petajoules [a]					
New Brunswick	47.9	44.3	45.2	45.0	44.9	47.6	34.3	23.9	23.8	17.5
Quebec	45.5	59	59.1	59.1	67.3	86.7	86.3	65.3	74	87.9
Ontario	71.8	88.2	83.4	85.1	85.9	84.2	76.3	78.3	100.4	16.9
Manitoba	26	15.2	3.5	3.5	12.2	12.9	23.7	28.8	27.6	33.9
Saskatchewan	1.5	1.5	1.8	1.7	1.7	1.6	1.6	1.6	1.6	1.6
Alberta	0	0	0	0	0	0	0	0	0	0
British Columbia	15	46.1	27.1	27.5	30.3	34.7	37.8	41.7	52.5	43.2
Canada	**207.7**	**254.3**	**220.1**	**221.9**	**242.3**	**267.7**	**260.0**	**239.6**	**279.9**	**201.0**
					High Case					
					Gigawatt hours					
New Brunswick	6592	5873	6525	6524	6524	4904	2544	2172	2163	2962
Quebec	12640	16401	16421	16421	18691	21081	18879	14938	19379	27179
Ontario	6263	6314	7950	7950	7950	6950	6950	6950	2850	1150
Manitoba	6978	2949	979	979	3379	3979	6579	7604	8204	8704
Saskatchewan	91	34	114	34	34	34	64	144	144	144
Alberta	-3	-2	-1	-1	-1	-1	-1	-1	-1	-1
British Columbia	1429	12322	7340	7210	7270	7200	6980	7080	9090	7690
Canada	**33990**	**43891**	**39328**	**39117**	**43847**	**44147**	**41995**	**38887**	**41829**	**47828**
					Petajoules [a]					
New Brunswick	47.9	44.3	45.2	44.9	44.9	43	34.3	23.9	23.8	26.7
Quebec	45.5	59	59.1	59.1	67.3	75.9	70	53.8	69.8	97.8
Ontario	71.8	88.2	83.5	84.8	84.8	73.8	74.4	76.6	30.6	12.9
Manitoba	26	15.2	3.5	3.5	12.2	14.3	23.7	27.4	29.5	31.3
Saskatchewan	1.5	1.5	1.8	1.7	1.7	1.6	1.6	1.6	1.6	1.6
Alberta	0	0	0	0	0	0	0	0	0	0
British Columbia	15	46.1	28	27.5	29.3	33.8	47.8	40.5	41.5	43.5
Canada	**207.7**	**254.3**	**221.1**	**221.5**	**240.2**	**242.4**	**251.8**	**223.8**	**196.8**	**213.8**

Notes: The numbers in this table have been rounded.
Available data on electricity exports during 1988 indicate that a lower level of exports is likely in 1988 than we projected.
This results from below average rainfall in Canada and lower than projected heavy fuel oil prices in certain U.S. markets.
[a] Converted from gigawatt hours using plant specific factors for fossil fuels, and 3.6 PJ/TW.h for hydro and 12.1 PJ/TW.h for nuclear.

Table A5-6
Net Electricity Exports by Fuel Type - Canada

Terawatt hours

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Hydro	25.6	34.1	28.1	28.2	33.1	36.5	36.3	31.2	37.3	40.1
Coal	5.5	7.2	7.9	7.0	6.7	8.5	6.3	7.5	9.1	4.4
Nuclear	2.5	2.2	2.7	3.6	4.0	3.1	4.4	3.7	1.2	0.3
Oil	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**34.0**	**43.9**	**39.1**	**39.2**	**44.2**	**48.5**	**47.4**	**42.8**	**48.0**	**45.2**

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Hydro	25.6	34.1	28.4	28.2	32.9	33.6	31.0	27.8	35.4	42.4
Coal	5.5	7.2	7.9	7.2	7.3	7.3	7.4	7.9	5.3	4.5
Nuclear	2.5	2.2	2.7	3.4	3.4	3.0	3.3	2.8	0.7	0.6
Oil	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**34.0**	**43.9**	**39.4**	**39.2**	**44.0**	**44.3**	**42.1**	**38.9**	**41.8**	**47.9**

Notes: The numbers in this table have been rounded.

Appendix 6

Table A6-1
Historical Data
Established Reserves and Cumulative Production of Marketable Natural Gas
Conventional Areas

(Exajoules)

	1967	**1968**	**1969**	**1970**	**1971**	**1972**	**1973**	**1974**	**1975**	**1976**
Initial Reserves	64.80	67.85	74.77	77.10	82.86	83.20	87.42	89.20	91.07	96.29
Cumulative Production	10.61	12.03	13.93	15.73	18.25	20.77	23.48	26.17	28.88	31.42
Remaining Reserves	54.19	55.82	60.84	61.37	64.61	62.43	63.94	63.03	62.19	64.87

	1977	**1978**	**1979**	**1980**	**1981**	**1982**	**1983**	**1984**	**1985**	**1986**
Initial Reserves	102.70	110.94	115.94	119.16	126.52	129.97	131.33	132.85	134.77	136.04
Cumulative Production	34.25	36.89	40.00	42.77	45.74	48.52	51.30	54.28	57.44	60.75
Remaining Reserves	68.45	74.05	75.94	76.39	80.78	81.45	80.03	78.57	77.33	75.29

Table A6-2
Historical Data and Projections
Gas-Directed Exploratory Drilling and Reserves Additions of Marketable Natural Gas
Conventional Areas

	Drilling (Millions of Metres)		Reserves Added (Exajoules)		Additions Rate (Petajoules per Kilometre)	
1965	0.76		4.80		6.32	
1966	0.85		1.34		1.58	
1967	0.68		4.96		7.29	
1968	0.91		3.04		3.34	
1969	0.88		6.92		7.86	
1970	1.24		2.34		1.89	
1971	1.11		5.76		5.19	
1972	1.56		0.34		0.22	
1973	1.69		4.22		2.50	
1974	1.49		1.78		1.19	
1975	1.34		1.87		1.40	
1976	1.87		5.22		2.79	
1977	2.21		6.41		2.90	
1978	2.63		8.23		3.13	
1979	2.78		5.00		1.80	
1980	3.50		3.22		0.92	
1981	2.67		7.36		2.76	
1982	1.58		3.45		2.18	
1983	1.14		1.36		1.19	
1984	1.43		1.52		1.06	
1985	1.50		1.92		1.28	
1986	1.12		1.27		1.13	
	Low Case	**High Case**	**Low Case**	**High Case**	**Low Case**	**High Case**
1987	1.53	1.53	0.20	0.20	0.13	0.13
1988	1.89	1.90	0.40	0.40	0.21	0.21
1989	1.35	1.90	1.81	2.52	1.34	1.33
1990	1.02	1.62	1.33	2.03	1.30	1.25
1991	0.89	1.54	1.12	1.84	1.26	1.19
1992	0.97	1.55	1.39	2.09	1.43	1.35
1995	2.01	2.57	3.14	3.76	1.56	1.46
2000	2.77	2.96	3.28	3.15	1.18	1.06
2005	2.93	3.41	2.58	2.61	0.88	0.77

Table A6-3
Ultimate Technical Potential And Reserves Additions of Marketable Natural Gas
Conventional Areas

(Exajoules)

Initial Established Reserves @ 31 December 1986	136
Remaining Technical Potential from New Discoveries & Other Appreciation	89
Ultimate Technical Potential	225
Reserves Additions (1987-2005) - Low Case	46
- High Case	51

Notes: [a] The ultimate technical potential of marketable natural gas from new discoveries and other appreciation is based on the 1983 Geological Survey of Canada's average expectation estimate.
[b] This technical potential estimate is based on known technology.

Table A6-4
Net Incremental Direct Costs for Natural Gas
Western Canada

Reserves Additions Increment (Exajoules)	Low Case ($C per Gigajoule)	High Case ($C per Gigajoule)
0 - 5	1.31	1.93
5 - 10	1.38	2.03
10 - 15	1.46	2.14
15 - 20	1.55	2.27
20 - 25	1.65	2.41
25 - 30	1.76	2.57
30 - 35	1.88	2.76
35 - 40	2.03	2.97
40 - 45	2.19	3.22
45 - 50	2.38	3.51
50 - 55	2.61	3.86
55 - 60	2.88	4.29
60 - 65	3.22	4.84
65 - 70	3.68	5.57
70 - 75	4.33	6.65

Note: Net incremental direct costs includes credit for by-products.

Table A6-5
Historical Data - Natural Gas Supply and Demand - Conventional Areas

(Petajoules)	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
End Use [a]	**672**	**741**	**851**	**914**	**1012**	**1131**	**1153**	**1266**	**1258**	**1319**
Own Use										
Pipeline fuel and losses	59	67	75	86	97	109	115	119	118	118
Reprocessing fuel	4	5	5	5	8	11	10	11	11	11
Total Own Use	**63**	**72**	**80**	**91**	**105**	**120**	**125**	**130**	**129**	**129**
Electricity Generation	73	85	64	99	100	148	200	173	195	139
Steam Production	0	0	0	0	0	0	0	0	0	0
Reprocessing Shrinkage	27	29	36	44	55	74	81	78	77	74
Domestic Demand	**835**	**927**	**1031**	**1148**	**1272**	**1472**	**1559**	**1647**	**1659**	**1662**
Exports	564	664	748	858	1003	1110	1130	1054	1019	1027
Total Disposition [b]	**1399**	**1591**	**1779**	**2006**	**2275**	**2582**	**2689**	**2701**	**2678**	**2689**
Total Production	**1341**	**1514**	**1769**	**2037**	**2260**	**2569**	**2741**	**2687**	**2728**	**2754**
Productive Capacity [c]	**n/a**	**1550**	**1800**	**2100**	**2400**	**2600**	**2750**	**2900**	**3050**	**3200**

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
End Use [a]	**1419**	**1505**	**1583**	**1582**	**1571**	**1623**	**1657**	**1775**	**1914**	**1856**
Own Use										
Pipeline fuel and losses	122	119	126	118	118	114	116	123	135	129
Reprocessing fuel	12	14	15	16	17	16	12	11	13	18
Total Own Use	**134**	**133**	**141**	**134**	**135**	**130**	**127**	**134**	**148**	**147**
Electricity Generation	132	106	104	84	69	61	75	68	56	60
Steam Production	0	0	0	0	0	0	0	0	0	2
Reprocessing Shrinkage	71	69	102	155	162	160	153	181	198	183
Domestic Demand	**1756**	**1813**	**1930**	**1956**	**1937**	**1974**	**2013**	**2158**	**2315**	**2247**
Exports	1077	949	1094	863	824	845	764	812	975	794
Total Disposition [b]	**2833**	**2762**	**3024**	**2819**	**2761**	**2819**	**2777**	**2970**	**3290**	**3041**
Total Production	**2872**	**2777**	**3007**	**2764**	**2739**	**2807**	**2664**	**2901**	**3162**	**2905**
Productive Capacity [c]	**3400**	**3650**	**4000**	**4400**	**4600**	**4850**	**5030**	**4850**	**4995**	**4790**

Notes: [a] For end use demand by fuel and sector see Table A4-5.
[b] Total disposition differs from total production because of synthetic natural gas and imports in disposition but not in production of natural gas, inventory changes, and statistical differences.
[c] Estimated from previous reports.

Table A6-6
Productive Capacity of Natural Gas from Established Reserves Under Contract

Low Case

(Petajoules)

	Alberta						British Columbia			Saskatchewan	N.W.T.	Ontario	Canada
	Non-Associated Gas	Cycling Gas	Solution Gas	Southeast Alberta	Deferred	Subtotal	Non-Associated Gas	Solution Gas	Subtotal				Total
1987	3182	180	142	394	3	3900	466	13	479	64	7	16	4466
1988	3043	197	140	377	3	3760	442	13	455	73	7	16	4310
1989	2869	197	123	367	4	3559	394	12	407	69	7	16	4057
1990	2680	208	104	360	6	3359	382	11	394	66	7	16	3841
1991	2486	242	89	355	7	3179	372	10	383	62	25	16	3664
1992	2277	240	76	351	9	2952	362	10	372	59	25	16	3424
1993	2079	238	66	348	18	2748	348	9	357	56	25	14	3200
1994	1884	224	58	344	27	2537	305	8	313	53	22	13	2939
1995	1710	205	51	239	35	2240	280	7	287	51	19	12	2609
1996	1556	132	44	209	43	1983	253	7	260	49	18	11	2322
1997	1439	107	40	205	52	1844	225	6	232	46	18	11	2150
1998	1253	102	36	202	58	1650	195	6	201	44	15	10	1919
1999	1136	92	32	182	62	1504	172	6	177	41	1	9	1732
2000	1028	86	29	147	68	1357	139	6	145	40	1	9	1551
2001	950	80	26	145	72	1273	122	5	127	37	1	8	1446
2002	879	72	24	141	77	1193	108	5	113	35	0	8	1349
2003	821	61	22	119	81	1104	91	5	96	34	0	7	1242
2004	745	54	20	111	85	1014	78	5	83	32	0	7	1136
2005	683	43	18	105	88	937	66	5	71	31	0	7	1045

Table A6-6 (Continued)

Productive Capacity of Natural Gas from Established Reserves Under Contract

(Petajoules)

High Case

	Alberta						British Columbia			Saskatchewan	N.W.T.	Ontario	Canada
	Non-Associated Gas	Cycling Gas	Solution Gas	Southeast Alberta	Deferred	Subtotal	Non-Associated Gas	Solution Gas	Subtotal				Total
1987	3181	180	142	394	3	3899	466	13	479	64	7	16	4465
1988	3042	197	140	377	3	3759	442	13	455	73	7	16	4310
1989	2875	197	123	367	4	3565	394	12	407	69	7	16	4063
1990	2708	208	104	360	6	3387	382	11	394	66	7	16	3868
1991	2557	242	89	355	7	3250	372	10	382	62	25	16	3735
1992	2368	240	76	351	9	3044	362	10	372	59	25	16	3515
1993	2163	238	66	348	18	2832	348	9	357	56	25	14	3284
1994	1954	224	58	344	27	2607	311	8	319	53	22	13	3015
1995	1767	205	51	239	35	2297	285	7	292	51	19	12	2671
1996	1599	132	44	209	43	2027	260	7	266	49	18	11	2372
1997	1461	107	40	205	52	1865	231	6	238	46	18	11	2177
1998	1266	102	36	202	58	1664	201	6	207	44	15	10	1939
1999	1135	92	32	182	62	1503	176	6	181	41	1	9	1735
2000	1011	86	29	147	68	1340	142	6	147	40	1	9	1537
2001	937	80	26	145	72	1260	124	5	129	37	1	8	1435
2002	877	72	24	141	77	1191	109	5	114	35	0	8	1348
2003	823	61	22	119	81	1106	90	5	95	34	0	7	1243
2004	750	54	20	111	85	1019	77	5	82	32	0	7	1140
2005	689	43	18	105	88	942	64	5	69	31	0	7	1049

Table A6-7
Productive Capacity of Natural Gas from Established Reserves Not As Yet Contracted

(Petajoules)

Low Case

	Alberta			British Columbia	Saskatchewan	Canada
	Uncontracted	B.E.R.	Subtotal			Total
1987	30	7	37	32	42	111
1988	59	13	72	55	49	176
1989	117	19	136	67	46	249
1990	203	25	227	74	44	346
1991	285	30	315	79	42	436
1992	363	35	398	87	40	525
1993	436	40	477	105	38	620
1994	476	45	521	131	36	688
1995	482	49	532	139	34	705
1996	487	53	540	148	32	721
1997	460	57	517	150	31	698
1998	430	60	489	149	29	667
1999	398	62	460	147	28	635
2000	364	64	428	143	26	596
2001	326	65	391	140	25	556
2002	288	67	355	134	24	513
2003	253	69	322	128	22	472
2004	220	70	291	120	21	431
2005	194	72	266	109	20	396

Table A6-7 (Continued)
Productive Capacity of Natural Gas from Established Reserves
Not As Yet Contracted

(Petajoules)

High Case

	Alberta			British Columbia	Saskatchewan	Canada
	Uncontracted	B.E.R.	Subtotal			Total
1987	30	7	37	32	42	111
1988	59	13	72	55	49	176
1989	117	19	136	67	46	249
1990	203	25	228	74	44	346
1991	286	30	316	80	42	438
1992	365	35	400	87	40	527
1993	440	40	480	112	38	630
1994	481	45	526	132	36	694
1995	489	49	539	140	34	713
1996	495	53	549	150	32	731
1997	469	57	527	152	31	709
1998	438	60	498	151	29	678
1999	406	62	468	149	28	645
2000	370	64	433	145	26	604
2001	329	65	395	141	25	560
2002	290	67	357	135	24	515
2003	253	69	322	129	22	472
2004	219	70	289	120	21	430
2005	192	72	264	110	20	394

Table A6-8
Productive Capacity of Natural Gas from All Sources

Low Case

(Petajoules)

	Established			Reserves Additions	Western Canada	Frontier		Canada
	Contracted	Uncontracted	Subtotal		Subtotal	Delta	Venture	Total
1987	4466	111	4576	12	4588	–	–	4588
1988	4310	176	4487	34	4521	–	–	4521
1989	4057	249	4306	63	4369	–	–	4369
1990	3841	346	4187	108	4295	–	–	4295
1991	3664	436	4101	180	4281	–	–	4281
1992	3424	525	3948	289	4237	–	–	4237
1993	3200	620	3820	448	4268	–	–	4268
1994	2939	688	3627	612	4239	–	–	4239
1995	2609	705	3313	821	4134	–	–	4134
1996	2322	721	3042	1064	4106	–	–	4106
1997	2150	698	2848	1308	4156	–	–	4156
1998	1919	667	2586	1576	4162	–	–	4162
1999	1732	635	2367	1806	4173	200	–	4373
2000	1551	596	2148	1980	4128	300	–	4428
2001	1446	556	2002	2121	4123	450	–	4573
2002	1349	513	1862	2254	4116	450	–	4566
2003	1242	472	1713	2373	4086	450	–	4536
2004	1136	431	1567	2510	4077	450	–	4527
2005	1045	396	1441	2617	4058	450	–	4508

Table A6-8 (Continued)
Productive Capacity of Natural Gas from All Sources

(Petajoules)

High Case

	Established			Reserves Additions	Western Canada	Frontier		Canada
	Contracted	Uncontracted	Subtotal		Subtotal	Delta	Venture	Total
1987	4465	111	4576	12	4588	–	–	4588
1988	4310	176	4486	36	4522	–	–	4522
1989	4063	249	4312	69	4381	–	–	4381
1990	3868	346	4214	122	4336	–	–	4336
1991	3735	438	4173	211	4384	–	–	4384
1992	3515	527	4042	347	4389	–	–	4389
1993	3284	630	3914	548	4462	–	–	4462
1994	3015	694	3709	813	4522	–	–	4522
1995	2671	713	3383	1127	4510	–	–	4510
1996	2372	731	3103	1421	4524	–	–	4524
1997	2177	709	2887	1759	4646	–	–	4646
1998	1939	678	2617	2109	4726	–	–	4726
1999	1735	645	2380	2227	4607	200	–	4807
2000	1537	604	2141	2340	4481	300	–	4781
2001	1435	560	1995	2463	4458	450	–	4908
2002	1348	515	1863	2618	4481	450	–	4931
2003	1243	472	1715	2763	4478	450	–	4928
2004	1140	430	1570	2851	4421	450	150	5021
2005	1049	394	1443	2886	4329	450	250	5029

Table A6-9
Historical Data - Natural Gas Exports

(Billions of Cubic Metres)

	Pacific Northwest	Mountain	California	Central	Northeast	Total
1971	5.2	3.0	10.0	6.9	0.7	25.8
1972	6.5	3.6	10.9	7.3	0.3	28.6
1973	6.8	3.7	11.0	7.4	0.2	29.1
1974	6.2	3.4	10.1	7.2	0.3	27.2
1975	5.5	3.1	10.8	7.1	0.3	26.8
1976	5.5	2.9	11.1	7.2	0.3	27.0
1977	6.1	2.9	11.1	7.9	0.3	28.3
1978	5.3	2.6	9.8	7.1	0.2	25.0
1979	5.9	2.8	11.0	8.1	0.5	28.3
1980	4.1	2.0	8.9	7.0	0.6	22.6
1981	3.5	1.8	7.7	7.0	1.6	21.6
1982	2.3	1.3	8.8	7.8	2.0	22.2
1983	2.3	0.9	8.1	7.4	1.5	20.2
1984	1.9	0.8	8.0	7.8	2.9	21.4
1985	2.4	1.0	11.4	9.2	2.1	26.1
1986	2.9	0.2	9.9	6.1	1.9	21.0
1987	4.1	0.2	13.5	7.6	2.5	28.0

Note: The data includes the following volumes exported under short-term Orders:
(Billions of Cubic Metres)

1984	0.1
1985	0.5
1986	6.2
1987	6.1

Table A 6 - 10
Composition of Canadian Natural Gas Exports By U.S. Demand Regions[a]

Billion Cubic Feet

Low Case

REGIONS	PNW	%[b]	CAL	%[b]	CTR	%[b]	NE	%[b]	TOTAL	%[b]
1987	151.8	65	478.0	28	269.7	2	89.7	4	989.2	6
1988	183.5	78	505.2	29	449.0	4	134.8	7	1272.5	8
1989	198.0	84	482.9	28	494.6	4	147.2	7	1322.4	8
1900	197.6	83	485.7	27	494.6	4	167.3	8	1345.2	8
1991	204.0	84	486.4	27	513.3	5	170.8	9	1374.5	8
1992	214.0	88	506.0	27	482.0	4	173.0	9	1375.0	8
1993	213.8	88	503.2	27	483.0	4	173.6	9	1373.6	8
1994	213.6	88	500.4	26	484.0	4	174.2	9	1372.2	8
1995	213.4	88	497.6	26	485.0	4	174.8	9	1370.8	8
1996	213.2	88	494.8	25	486.0	4	175.4	9	1369.4	8
1997	213.0	88	492.0	25	487.0	4	176.0	9	1368.0	8
1998	213.6	88	491.2	25	492.0	4	175.8	9	1372.6	8
1999	214.2	88	490.4	24	497.0	4	175.6	9	1377.2	8
2000	214.8	88	489.6	24	502.0	4	175.4	9	1381.8	8
2001	215.4	88	488.8	24	507.0	5	175.2	9	1386.4	8
2002	216.0	88	488.0	24	512.0	5	175.0	9	1391.0	8
2003	216.2	88	486.8	24	506.8	5	175.2	9	1385.0	8
2004	216.4	88	485.6	24	501.6	5	175.4	9	1379.0	8
2005	216.6	88	484.4	24	496.4	5	175.6	9	1373.0	8
2006	216.8	88	483.2	24	491.2	5	175.8	10	1367.0	8
2007	217.0	88	482.0	24	486.0	5	176.0	10	1361.0	8

Note: [a] The numbers shown in this Table and in Table A6-11 differ slightly because the supply/demand balances in A6-11 were completed prior to making final adjustments to the export numbers. The discrepancy is negligible.
[b] Percent is Canadian supply as a percentage of regional U.S. natural gas consumption.

Legend: PNW = Pacific Northwest and Mountain Demand Regions
CAL = California
CTR = West North Central, West South Central, East North Central and East South Central Demand Regions
NE = New England, New York and Mid Atlantic Demand Regions

Table A 6 - 10 (Continued)
Composition of Canadian Natural Gas Exports By U.S. Demand Regions[a]

Billion Cubic Feet

High Case

REGIONS	PNW	%[b]	CAL	%[b]	CTR	%[b]	NE	%[b]	TOTAL	%[b]
1987	151.8	65	478.0	28	269.7	2	89.7	4	989.2	6
1988	183.5	78	505.2	29	449.0	4	134.8	7	1272.5	8
1989	198.0	84	482.9	27	494.6	4	147.2	7	1322.4	8
1900	197.6	83	485.7	27	494.6	4	167.3	8	1345.2	8
1991	204.0	85	486.4	26	513.3	5	170.8	8	1374.5	8
1992	211.0	88	500.0	27	549.0	5	182.0	8	1442.0	8
1993	212.4	88	498.2	26	547.0	5	182.2	8	1439.8	8
1994	213.8	88	496.4	25	545.0	5	182.4	8	1437.6	8
1995	215.2	88	494.6	25	543.0	5	182.6	8	1435.4	8
1996	216.6	88	492.8	24	541.0	5	182.8	8	1433.2	8
1997	218.0	88	491.0	23	539.0	5	183.0	8	1431.0	8
1998	219.0	88	490.6	23	532.0	5	181.2	8	1422.8	8
1999	220.0	88	490.2	23	525.0	5	179.4	8	1414.6	8
2000	221.0	88	489.8	23	518.0	4	177.6	8	1406.4	8
2001	222.0	88	489.4	23	511.0	4	175.8	8	1398.2	8
2002	223.0	88	489.0	23	504.0	4	174.0	8	1390.0	8
2003	223.8	88	488.8	23	496.4	4	175.2	8	1384.2	8
2004	224.6	88	488.6	23	488.8	4	176.4	8	1378.4	8
2005	225.4	88	488.4	23	481.2	4	177.6	9	1372.6	8
2006	226.2	88	488.2	23	473.6	4	178.8	9	1366.8	8
2007	227.0	88	488.0	23	466.0	4	180.0	9	1361.0	8

Note: [a] The numbers shown in this Table and in Table A6-11 differ slightly because the supply/demand balances in A6-11 were completed prior to making final adjustments to the export numbers. The discrepancy is negligible.
[b] Percent is Canadian supply as a percentage of regional U.S. natural gas consumption.

Legend: PNW = Pacific Northwest and Mountain Demand Regions
CAL = California
CTR = West North Central, West South Central, East North Central and East South Central Demand Regions
NE = New England, New York and Mid Atlantic Demand Regions

Table A 6 - 10 (Continued)
Composition of Canadian Natural Gas Exports By U.S. Demand Regions[a]

Billion Cubic Metres

Low Case

REGIONS	PNW	%[b]	CAL	%[b]	CTR	%[b]	NE	%[b]	TOTAL	%[b]
1987	4.3	65	13.5	28	7.6	2	2.5	4	28.0	6
1988	5.2	78	14.3	29	12.7	4	3.8	7	36.0	8
1989	5.6	84	13.7	28	14.0	4	4.2	7	37.5	8
1900	5.6	83	13.8	27	14.0	4	4.7	8	38.1	8
1991	5.8	84	13.8	27	14.5	5	4.8	9	38.9	8
1992	6.1	88	14.3	27	13.7	4	4.9	9	39.0	8
1993	6.1	88	14.3	27	13.7	4	4.9	9	38.9	8
1994	6.1	88	14.2	26	13.7	4	4.9	9	38.9	8
1995	6.0	88	14.1	26	13.7	4	5.0	9	38.8	8
1996	6.0	88	14.0	25	13.8	4	5.0	9	38.8	8
1997	6.0	88	13.9	25	13.8	4	5.0	9	38.8	8
1998	6.1	88	13.9	25	13.9	4	5.0	9	38.9	8
1999	6.1	88	13.9	24	14.1	4	5.0	9	39.0	8
2000	6.1	88	13.9	24	14.2	4	5.0	9	39.1	8
2001	6.1	88	13.8	24	14.4	5	5.0	9	39.3	8
2002	6.1	88	13.8	24	14.5	5	5.0	9	39.4	8
2003	6.1	88	13.8	24	14.4	5	5.0	9	39.2	8
2004	6.1	88	13.8	24	14.2	5	5.0	9	39.1	8
2005	6.1	88	13.7	24	14.1	5	5.0	9	38.9	8
2006	6.1	88	13.7	24	13.9	5	5.0	10	38.7	8
2007	6.1	88	13.7	24	13.8	5	5.0	10	38.6	8

Note: [a] The numbers shown in this Table and in Table A6-11 differ slightly because the supply/demand balances in A6-11 were completed prior to making final adjustments to the export numbers. The discrepancy is negligible.
[b] Percent is Canadian supply as a percentage of regional U.S. natural gas consumption.

Legend: PNW = Pacific Northwest and Mountain Demand Regions
CAL = California
CTR = West North Central, West South Central, East North Central and East South Central Demand Regions
NE = New England, New York and Mid Atlantic Demand Regions

Table A 6 - 10 (Continued)
Composition of Canadian Natural Gas Exports By U.S. Demand Regions[a]

Billion Cubic Metres

High Case

REGIONS	PNW	%[b]	CAL	%[b]	CTR	%[b]	NE	%[b]	TOTAL	%[b]
1987	4.3	65	13.5	28	7.6	2	2.5	4	28.0	6
1988	5.2	78	14.3	29	12.7	4	3.8	7	36.0	8
1989	5.6	84	13.7	27	14.0	4	4.2	7	37.5	8
1900	5.6	83	13.8	27	14.0	4	4.7	8	38.1	8
1991	5.8	85	13.8	26	14.5	5	4.8	8	38.9	8
1992	6.0	88	14.2	27	15.6	5	5.2	8	40.8	8
1993	6.0	88	14.1	26	15.5	5	5.2	8	40.8	8
1994	6.1	88	14.1	25	15.4	5	5.2	8	40.7	8
1995	6.1	88	14.0	25	15.4	5	5.2	8	40.7	8
1996	6.1	88	14.0	24	15.3	5	5.2	8	40.6	8
1997	6.2	88	13.9	23	15.3	5	5.2	8	40.5	8
1998	6.2	88	13.9	23	15.1	5	5.1	8	40.3	8
1999	6.2	88	13.9	23	14.9	5	5.1	8	40.1	8
2000	6.3	88	13.9	23	14.7	4	5.0	8	39.8	8
2001	6.3	88	13.9	23	14.5	4	5.0	8	39.6	8
2002	6.3	88	13.9	23	14.3	4	4.9	8	39.4	8
2003	6.3	88	13.8	23	14.1	4	5.0	8	39.2	8
2004	6.4	88	13.8	23	13.8	4	5.0	8	39.0	8
2005	6.4	88	13.8	23	13.6	4	5.0	9	38.9	8
2006	6.4	88	13.8	23	13.4	4	5.1	9	38.7	8
2007	6.4	88	13.8	23	13.2	4	5.1	9	38.6	8

Note: [a] The numbers shown in this Table and in Table A6-11 differ slightly because the supply/demand balances in A6-11 were completed prior to making final adjustments to the export numbers. The discrepancy is negligible.
[b] Percent is Canadian supply as a percentage of regional U.S. natural gas consumption.

Legend: PNW = Pacific Northwest and Mountain Demand Regions
CAL = California
CTR = West North Central, West South Central, East North Central and East South Central Demand Regions
NE = New England, New York and Mid Atlantic Demand Regions

(Petajoules)

Low Case

	End Use	Pipeline Fuel & Losses	Reprocessing Fuel	Electricity Generation [a]	Reprocessing Shrinkage	Domestic Demand	Exports [b]	Total Primary Demand	Productive Capacity	Adjusted Productive Capacity [c]
1987	1824	137	19	66	199	2244	1060	3304	4588	4593
1988	1890	152	21	74	224	2362	1362	3724	4521	4565
1989	1927	157	21	77	230	2412	1416	3828	4370	4496
1990	1959	160	22	77	234	2452	1440	3892	4295	4437
1991	2005	165	22	80	240	2512	1471	3983	4280	4420
1992	2056	170	23	89	246	2583	1499	4081	4237	4463
1993	2101	173	23	93	249	2640	1499	4138	4267	4488
1994	2143	176	24	103	252	2698	1499	4196	4239	4520
1995	2183	178	24	114	256	2756	1499	4254	4135	4518
1996	2217	180	24	121	259	2801	1499	4300	4106	4496
1997	2254	182	24	120	261	2842	1499	4340	4157	4439
1998	2283	184	24	114	263	2868	1499	4367	4162	4462
1999	2322	187	25	140	267	2941	1499	4439	4374	4670
2000	2371	189	25	119	269	2973	1499	4472	4428	4718
2001	2416	192	25	126	273	3033	1499	4531	4573	4811
2002	2459	194	26	126	275	3080	1499	4579	4566	4755
2003	2501	194	26	94	276	3091	1499	4589	4537	4740
2004	2524	197	26	119	279	3145	1499	4643	4527	4743
2005	2550	198	26	123	281	3179	1499	4677	4508	4716

Note: [a] The numbers shown in this column are different from those in Tables 4-17 and A10-1 because the supply/demand balances in A6-11 were completed prior to making final adjustments to the electricity generation numbers. The discrepancies are generally small.
[b] The numbers shown in this column are slightly different from those in Table A6-10 because the supply/demand balances in A6-11 were completed prior to making final adjustments to the export numbers. The discrepancy is negligible.
[c] Productive capacity adjusted to reflect that quantities produced equal total primary demand.

Table A6-11 (Continued)
Natural Gas Supply and Demand
Canada

(Petajoules)

High Case

	End Use	Pipeline Fuel & Losses	Reprocessing Fuel	Electricity Generation	Reprocessing Shrinkage	Domestic Demand	Exports [a]	Total Primary Demand	Productive Capacity	Adjusted Productive Capacity [b]
1987	1824	137	19	66	198	2243	1060	3303	4587	4593
1988	1924	154	21	71	222	2392	1362	3754	4522	4566
1989	2006	161	22	78	229	2496	1416	3911	4382	4502
1990	2116	167	23	78	245	2629	1440	4069	4336	4458
1991	2204	174	24	79	253	2733	1471	4205	4384	4478
1992	2284	180	24	83	260	2831	1499	4330	4389	4568
1993	2368	184	25	90	267	2935	1499	4433	4462	4667
1994	2478	189	26	100	275	3067	1499	4565	4522	4785
1995	2531	192	26	127	280	3156	1499	4655	4510	4885
1996	2566	194	26	120	282	3188	1499	4687	4524	4835
1997	2608	198	27	142	286	3261	1499	4760	4645	4868
1998	2645	199	27	124	288	3283	1499	4781	4726	4991
1999	2675	201	27	129	290	3322	1499	4821	4806	5069
2000	2713	204	27	128	293	3364	1499	4863	4780	5056
2001	2753	207	28	126	295	3409	1499	4907	4908	5109
2002	2775	209	28	143	298	3453	1499	4952	4931	5078
2003	2808	211	28	130	299	3476	1499	4975	4928	5091
2004	2828	212	28	139	301	3508	1499	5006	5021	5204
2005	2846	213	28	143	303	3532	1499	5031	5029	5215

Note: [a] The numbers shown in this column are slightly different from those in Table A6-10 because the supply/demand balances in A6-11 were completed prior to making final adjustments to the export numbers. The discrepancy is negligible.
[b] Productive capacity adjusted to reflect that quantities produced equal total primary demand.

Appendix 7

Table A7-1
Historical Data
Initial Established Reserves and Remaining Reserves of Conventional Crude Oil
Conventional Areas

(Millions of Cubic Metres)

	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
Initial Reserves										
Light Crude Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1900.8	1890.0
Heavy Crude Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	308.4	317.2
Total	**2154.2**	**2258.0**	**2324.5**	**2348.7**	**2387.5**	**2406.8**	**2416.9**	**2413.5**	**2209.2**	**2207.2**
Remaining Reserves										
Light Crude Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	901.2	826.2
Heavy Crude Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	128.1	127.9
Total	**1610.5**	**1655.0**	**1659.2**	**1611.8**	**1573.4**	**1513.5**	**1420.6**	**1320.2**	**1029.3**	**954.1**

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Initial Reserves										
Light Crude Oil	1920.7	1939.4	1935.2	1935.4	1980.4	2055.1	2085.5	2164.8	2217.2	2264.2
Heavy Crude Oil	325.1	325.6	352.3	378.9	355.7	365.6	385.7	404.1	419.0	434.4
Total	**2245.8**	**2265.0**	**2287.5**	**2314.3**	**2336.1**	**2420.7**	**2471.2**	**2568.9**	**2636.2**	**2698.6**
Remaining Reserves										
Light Crude Oil	794.9	752.4	679.1	615.4	598.2	616.5	595.2	612.9	609.0	600.7
Heavy Crude Oil	124.4	114.1	128.4	144.3	117.3	119.2	123.8	127.7	128.4	130.1
Total	**919.3**	**866.5**	**807.5**	**759.7**	**715.5**	**735.7**	**719.0**	**740.6**	**737.4**	**730.8**

Note: N/A indicates that the data is not available.

Source: Canadian Petroleum Association 1967-1974
National Energy Board 1975-1986

Table A7-2
Established Reserves of Conventional Crude Oil and Related Productive Capacity
Conventional Areas

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	Productive Capacity from Remaining Reserves at 31/12/86								
				1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			(Thousands of Cubic Metres per Day)								
Light Crude Oil												
Northwest Territories	35.200	7.111	28.089	4.3	4.6	4.6	4.6	4.6	4.6	4.1	2.5	1.5
British Columbia	84.477	64.731	19.746	5.8	5.2	4.6	4.1	3.7	3.3	2.3	1.4	0.8
Alberta	1945.658	1439.667	505.991	132.6	126.0	112.3	98.0	84.8	73.8	50.7	29.7	18.7
Saskatchewan	154.022	117.786	36.236	10.3	9.7	8.8	8.0	7.2	6.6	4.8	2.7	1.5
Manitoba	34.572	24.848	9.724	2.1	2.0	1.8	1.7	1.6	1.4	1.2	0.8	0.5
Ontario	10.261	9.357	0.904	0.4	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.0
Subtotal	**2264.190**	**1663.500**	**600.690**	**155.4**	**147.8**	**132.4**	**116.6**	**102.0**	**89.8**	**63.1**	**37.1**	**23.0**
Adjusted Subtotal - Low Case				156.7	149.5	134.2	119.3	105.1	92.9	65.4	37.3	22.2
Adjusted Subtotal - High Case				156.7	152.7	138.9	124.3	110.1	97.7	69.3	39.0	22.7
Heavy Crude Oil												
Alberta	140.806	87.562	53.244	20.0	18.3	15.7	13.4	11.5	9.9	6.4	2.9	1.2
Saskatchewan	293.335	216.549	76.786	22.8	21.2	19.1	17.2	15.4	13.8	10.0	5.7	2.4
Manitoba	0.266	0.225	0.041	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	**434.407**	**304.336**	**130.071**	**42.8**	**39.5**	**34.8**	**30.6**	**26.9**	**23.7**	**16.4**	**8.7**	**3.6**
Adjusted Subtotal - Low Case				43.1	41.6	36.3	32.2	28.0	24.2	16.0	7.8	2.9
Adjusted Subtotal - High Case				43.1	43.6	40.5	37.4	32.9	28.4	17.6	6.7	1.7
Total Crude Oil												
Northwest Territories	35.200	7.111	28.089	4.3	4.6	4.6	4.6	4.6	4.6	4.1	2.5	1.5
British Columbia	84.477	64.731	19.746	5.8	5.2	4.6	4.1	3.7	3.3	2.3	1.4	0.8
Alberta	2086.464	1527.229	559.235	152.6	144.3	128.0	111.5	96.3	83.7	57.1	32.6	19.9
Saskatchewan	447.357	334.335	113.022	33.1	30.8	27.9	25.1	22.6	20.4	14.8	8.4	3.9
Manitoba	34.838	25.073	9.765	2.2	2.0	1.8	1.7	1.6	1.4	1.2	0.8	0.5
Ontario	10.261	9.357	0.904	0.4	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.0
Total	**2698.597**	**1967.836**	**730.761**	**198.3**	**187.2**	**167.3**	**147.2**	**128.9**	**113.5**	**79.5**	**45.8**	**26.6**
Adjusted Total - Low Case				**199.8**	**191.1**	**170.5**	**151.5**	**133.1**	**117.1**	**81.4**	**45.1**	**25.1**
Adjusted Total - High Case				**199.8**	**196.3**	**179.4**	**161.7**	**143.0**	**126.1**	**86.9**	**45.7**	**24.4**

Note: The productive capacity from established reserves was adjusted upward in both low and high cases to account for infill driling and workovers.
Productive capacity in the low case was then reduced for both light and heavy crude by 2 and 5 percent respectively , to account for reserves which are uneconomic .

Table A7-3

Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Light Crude Oil

	Initial Established Reserves at 31/12/86 (Millions of Cubic Metres)	Cumulative Production to 31/12/86 (Millions of Cubic Metres)	Remaining Established Reserves at 31/12/86 (Millions of Cubic Metres)	Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day) 1987	1988	1989	1990	1991	1992	1995	2000	2005
Northwest Territories												
IPL Norman Wells												
Norman Wells	35.200	7.111	28.089	4300	4600	4600	4600	4600	4600	4052	2458	1490
Pipeline Total	35.200	7.111	28.089	4300	4600	4600	4600	4600	4600	4052	2458	1490
NWT Total	**35.200**	**7.111**	**28.089**	**4300**	**4600**	**4600**	**4600**	**4600**	**4600**	**4052**	**2458**	**1490**
British Columbia												
Blueberry Taylor Pipelines												
Aitken Creek-Gething A	1.100	0.964	0.136	80	64	51	40	32	26	13	0	0
Blueberry Debolt	2.642	2.153	0.489	111	103	96	89	83	77	62	44	30
Eagle Belloy-Kisk 80%	1.224	0.450	0.774	321	274	234	200	170	145	90	41	18
Eagle West Belloy A 80%	5.120	2.763	2.357	989	840	714	606	515	438	268	118	52
Inga-Inga Total	6.250	5.405	0.845	309	271	237	208	182	160	107	55	28
Stoddart West Total	1.250	0.519	0.731	270	256	222	192	166	144	93	45	0
Miscellaneous	0.589	0.346	0.243	43	40	36	34	31	29	23	17	13
Pipeline Total	18.175	12.600	5.575	2125	1850	1593	1372	1183	1021	660	322	144
Trans-Prairie Pipelines Ltd. Beaton River												
Beatton R.Halfway Total	1.761	1.444	0.317	120	120	112	95	80	67	40	17	0
Beatton Rvr W. Bluesky A	0.963	0.752	0.211	54	46	40	35	31	27	21	14	11
Eagle Belloy-Kisk 20%	0.306	0.113	0.193	80	68	58	49	42	36	22	10	4
Eagle West Belloy A 20%	1.280	0.691	0.589	247	210	178	151	128	109	67	29	13
Milligan Creek-Halfway	7.100	6.647	0.453	194	165	140	119	101	86	53	23	8
Peejay-Halfway	10.311	9.271	1.040	360	359	333	287	247	212	135	64	0
Weasel-Halfway	3.400	2.815	0.585	240	206	176	151	129	110	69	31	14
Wildmint-Halfway	1.615	1.439	0.176	90	85	68	54	43	35	17	0	0
Miscellaneous	1.949	1.631	0.318	111	100	90	81	73	66	50	19	0
Pipeline Total	28.685	24.803	3.882	1499	1362	1199	1026	879	753	478	211	52
Trans-Prairie Pipelines Ltd. Boundary Lake Taylor												
Boundary Lake Unit No 1	19.000	13.175	5.825	1083	1014	949	888	831	778	638	458	329
Boundary Lake Unit No 2	11.550	9.685	1.865	528	479	434	394	357	324	241	148	90
Bdry Lk Dome 1 & 2	3.400	2.764	0.636	147	136	125	116	107	98	77	51	34
Miscellaneous	0.769	0.422	0.347	115	102	91	81	72	64	46	25	14
Pipeline Total	34.719	26.046	8.673	1875	1733	1601	1480	1369	1266	1003	684	469
Trunk and Tank Car												
B.C. Trucked Oil	2.898	1.282	1.616	281	266	251	238	224	212	179	135	102
Pipeline Total	2.898	1.282	1.616	281	266	251	238	224	212	179	135	102
B.C. Total	**84.477**	**64.731**	**19.746**	**5783**	**5213**	**4646**	**4117**	**3656**	**3253**	**2321**	**1353**	**768**

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Light Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
B.C. Total	**84.477**	**64.731**	**19.746**	**5783**	**5213**	**4646**	**4117**	**3656**	**3253**	**2321**	**1353**	**768**
Alberta												
Bow River Pipe Lines Ltd.												
Cessford Banff B	0.579	0.181	0.398	84	75	68	61	56	51	41	30	24
Halkirk E. Ellerslie A	0.340	0.048	0.292	109	101	87	75	65	56	36	17	7
Halkirk East Field Other	0.277	0.080	0.197	79	68	59	51	44	38	25	12	0
Halkirk Upper Mann. I	0.850	0.082	0.768	126	126	126	126	126	126	108	65	39
Halkirk Field Other	0.300	0.082	0.218	75	74	66	57	49	43	28	14	0
Provost Viking CAK	10.800	7.437	3.363	571	521	478	442	411	385	321	252	207
Provost Field Other	1.700	0.604	1.096	480	441	370	311	261	219	129	54	0
Shouldice Field Total	0.644	0.110	0.534	112	99	88	79	71	65	49	33	24
Youngstown Arcs	0.656	0.324	0.332	160	169	133	105	83	66	32	0	0
Miscellaneous & Undef	1.847	0.481	1.366	180	180	180	180	180	180	179	112	77
Pipeline Total	17.993	9.429	8.564	1978	1857	1659	1492	1351	1232	953	593	382
Cremona Pipeline System												
Caroline Rundle A	2.440	1.861	0.579	258	220	187	159	135	115	71	31	0
Crossfield Field Total	4.010	3.310	0.700	210	202	182	164	147	133	97	57	17
Crossfield East Fld Tot	1.020	0.833	0.187	87	84	71	60	51	43	25	0	0
Garrington Card A&B 27%	0.872	0.745	0.127	45	44	39	35	31	28	20	0	0
Garrington Viking A 27%	0.243	0.133	0.110	38	33	29	25	23	21	16	11	0
Garrington Wabamun A	1.300	1.096	0.204	78	68	59	51	44	38	25	12	6
Garrington Fld Othr 27%	0.483	0.284	0.199	73	70	61	53	46	40	27	15	0
Harmattan East Rundle	11.790	10.495	1.295	511	441	381	328	283	245	157	75	36
Harmattan East Viking E	0.844	0.486	0.358	223	178	142	114	91	72	37	0	0
Harmattan Elkton Run. C	11.500	9.331	2.169	723	639	564	498	439	388	267	143	76
Lochend Cardium A	0.750	0.344	0.406	138	119	104	93	83	76	59	43	0
Miscellaneous & Undef	0.441	0.183	0.258	71	65	59	54	49	45	34	21	13
Pipeline Total	35.693	29.101	6.592	2460	2167	1884	1639	1429	1248	840	413	150
Federated Pipe Lines Ltd.												
Carson Creek N BHL A&B	23.955	21.184	2.771	1704	1300	999	772	601	471	234	80	0
Judy Creek Viking A	0.860	0.681	0.179	91	77	65	54	46	39	23	0	0
Judy Creek BHL A	56.000	44.854	11.146	2175	2099	1836	1622	1450	1307	1001	708	539
Judy Creek BHL B	17.000	15.067	1.933	673	590	519	458	406	360	256	152	0
Meekwap D-2A	4.750	3.052	1.698	1000	1024	791	574	417	303	116	23	0
Swan Hills BHL C	26.000	18.358	7.642	1359	1248	1151	1064	987	917	749	555	428
Swan Hills BHL A&B	114.100	85.301	28.799	5225	4728	4299	3926	3599	3312	2629	1883	1414
Swan Hills South BHL A&B	70.830	52.743	18.087	2854	2674	2509	2357	2217	2089	1758	1348	1057
Virginia Hills Belloy A	4.328	1.637	2.691	1100	1099	980	803	657	538	295	108	39
Virginia Hills BHL	23.800	19.930	3.870	1700	1783	1516	1217	976	783	405	134	0
Miscellaneous & Undef	1.432	0.782	0.650	180	170	165	149	135	122	90	55	33
Pipeline Total	343.055	263.589	79.466	18061	16798	14834	13002	11496	10246	7561	5050	3514

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Light Crude Oil

	Initial Established Reserves at 31/12/86 (Millions of Cubic Metres)	Cumulative Production to 31/12/86 (Millions of Cubic Metres)	Remaining Established Reserves at 31/12/86 (Millions of Cubic Metres)	Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day) 1987	1988	1989	1990	1991	1992	1995	2000	2005
Gibson Petroleum Company Limited												
Bellshill Blairmore	13.278	8.548	4.730	1992	1707	1463	1253	1074	920	579	267	0
Killam Glauconitic S	0.760	0.134	0.626	240	221	195	168	144	124	79	37	0
Provost Blairmore B	0.820	0.685	0.135	68	57	48	40	34	28	16	0	0
Miscellaneous & Undef	0.631	0.196	0.435	199	170	145	125	107	91	57	0	0
Pipeline Total	15.489	9.563	5.926	2485	2157	1852	1587	1360	1165	733	305	0
Gulf Alberta Pipeline												
Bashaw Field Total	1.141	0.613	0.528	170	163	144	127	112	99	68	36	19
Chain Field Total	0.462	0.091	0.371	130	128	114	98	85	73	46	22	8
Chigwell Viking E	0.400	0.126	0.274	121	101	86	73	63	54	36	15	0
Chigwell Field Other	1.200	0.853	0.347	140	120	104	91	81	72	54	0	0
Clive D-2A	3.250	2.256	0.994	350	335	297	258	224	195	128	63	13
Clive D-3A	7.030	5.078	1.952	551	498	450	406	367	331	244	147	88
Drumheller D-2A	1.820	1.392	0.428	160	142	124	108	93	81	53	26	13
Drumheller D-2B	2.550	1.768	0.782	414	336	272	220	179	145	77	27	2
Erskine D-3	3.920	3.534	0.386	150	149	135	116	100	86	55	0	0
Ewing Lake Field Total	0.969	0.778	0.191	88	76	64	55	46	39	24	0	0
Fenn-Big Valley D-2A	53.500	45.999	7.501	3073	2409	1944	1605	1350	1152	768	455	303
Fenn-Big Valley D-3F	2.232	1.975	0.257	96	76	62	52	45	39	27	17	12
Fenn West D-2A	1.680	1.255	0.425	180	179	151	124	103	85	48	18	0
Fenn West D-3E	0.592	0.263	0.329	180	163	127	99	77	60	28	8	0
Hussar Glauconite A	3.800	2.939	0.861	265	237	212	190	170	152	109	63	36
Hussar Field Other	0.962	0.746	0.216	94	83	74	66	58	52	36	0	0
Joffre D-2	8.600	6.848	1.752	380	380	358	320	287	259	196	133	96
Joffre D-3B	0.700	0.058	0.642	150	150	143	129	117	106	78	47	28
Michichi Field Total	0.359	0.081	0.278	129	109	92	78	66	56	34	13	0
Mikwan Field Total	0.522	0.243	0.279	105	88	75	64	55	48	33	19	12
Nevis Field Total	0.800	0.519	0.281	125	102	85	71	61	53	36	21	0
Parflesh U.Mann G	0.640	0.417	0.223	75	66	58	52	46	40	28	15	8
Stettler D-2A	4.200	3.957	0.243	87	78	70	63	56	50	36	21	0
Stettler D-3A	3.690	3.202	0.488	160	143	128	114	102	91	65	37	21
Watts Banff H	0.672	0.038	0.634	265	265	221	182	151	125	70	27	10
Watts Field Other	0.430	0.059	0.371	122	142	121	103	87	74	45	19	8
Wayne-Rosedale Bsl Qtz B	0.908	0.520	0.388	136	115	99	86	75	67	48	30	21
Wayne-Rosedale Fld Other	0.559	0.236	0.323	78	72	67	62	58	54	44	33	26
West Drumheller D-2A	4.800	4.395	0.405	128	117	106	96	88	80	60	37	0
Wood River D-2C	0.450	0.325	0.125	75	59	47	37	29	23	11	0	0
Wood River Field Other	0.708	0.286	0.422	103	92	82	74	67	61	47	32	24
Miscellaneous & Undef	25.170	19.524	5.646	1400	1412	1262	1127	1012	914	692	468	337
Pipeline Total	138.716	110.374	28.342	9690	8601	7390	6363	5525	4831	3340	1862	1094

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Light Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
The Imperial Pipe Line Company, Limited-Ellerslie												
Acheson D-3A	21.150	17.476	3.674	2200	2398	1721	1212	854	602	210	36	0
Acheson Field Other	1.154	0.872	0.282	125	119	101	85	71	60	36	0	0
Acheson East Blairmore B	0.750	0.481	0.269	137	109	89	73	61	52	33	0	0
Golden Spike D-3A	28.300	27.800	0.500	369	285	219	169	130	100	0	0	0
Morinville D-3B	1.860	1.555	0.305	111	90	74	62	53	46	31	18	12
Miscellaneous & Undef	8.165	6.416	1.749	376	350	325	303	282	262	211	147	102
Pipeline Total	61.379	54.600	6.779	3318	3352	2532	1907	1454	1124	523	203	115
The Imperial Pipe Line Company, Limited-Excelsior												
Excelsior D-2	4.400	4.193	0.207	129	101	80	63	49	39	19	0	0
Fairydell-Bon Accord D3A	2.070	1.798	0.272	67	60	54	49	44	40	31	21	15
Miscellaneous & Undef	1.037	0.802	0.235	75	67	60	54	49	45	34	23	0
Pipeline Total	7.507	6.793	0.714	272	230	195	167	143	124	84	44	15
The Imperial Pipe Line Company, Limited-Leduc												
Leduc Woodbend D-2A	14.150	14.064	0.086	76	60	48	38	11	0	0	0	0
Leduc Woodbend D-3A	39.800	38.745	1.055	597	504	425	359	303	256	44	0	0
Miscellaneous & Undef	7.000	6.561	0.439	99	90	82	75	69	63	51	37	28
Pipeline Total	60.950	59.370	1.580	773	655	556	473	383	319	95	37	28
The Imperial Pipe Line Company, Limited-Redwater												
Redwater D-3	130.000	123.293	6.707	2275	1953	1690	1473	1291	1139	805	489	320
Redwater Uml Viking A	0.257	0.164	0.093	50	42	35	30	25	22	12	0	0
Miscellaneous & Undef	0.564	0.313	0.251	94	84	76	68	61	54	39	0	0
Pipeline Total	130.821	123.770	7.051	2421	2081	1802	1571	1378	1216	857	489	320
Murphy Milk River Pipeline												
Coutts Total	0.600	0.495	0.105	53	44	37	31	25	21	12	0	0
Manyberries Sunb O+OO	0.832	0.283	0.549	210	195	167	144	124	107	68	32	2
Manyberries Other	1.750	0.786	0.964	320	320	312	273	234	201	127	59	0
Turin Upper Mannville H	0.600	0.188	0.412	120	119	110	98	87	77	53	29	16
Turin Field Other	0.909	0.256	0.653	160	151	135	121	110	100	78	54	41
Miscellaneous & Undef	1.277	1.109	0.168	79	69	61	53	47	41	28	0	0
Pipeline Total	5.968	3.117	2.851	943	900	825	722	629	549	368	176	60
Norcen Energy Resources Ltd.												
Joarcam Field Total	18.006	15.620	2.386	850	825	773	665	573	493	314	148	0
Pipeline Total	18.006	15.620	2.386	850	825	773	665	573	493	314	148	0

Table A7-3 (Continued)

Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Light Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
Peace Pipe Line Ltd.												
Ante Creek BHL	2.550	1.846	0.704	201	180	162	146	131	118	86	50	29
Bonanza Boundary A	1.000	0.302	0.698	90	100	100	98	90	82	65	47	37
Cherhill Lgt Field Total	2.485	1.516	0.969	275	289	256	226	200	176	121	64	34
Edson Field Total	1.100	0.986	0.114	97	77	65	55	16	0	0	0	0
Gift Slave Pt A+C+E	1.400	0.269	1.131	220	210	210	206	185	166	122	78	53
Gift Field Other	0.740	0.112	0.628	106	93	82	73	66	60	47	35	27
Grand Prairie Halfway A	0.480	0.126	0.354	99	99	88	74	63	54	37	23	16
Fox Creek BHL A	0.650	0.221	0.429	180	183	152	124	102	83	45	16	6
Goose River BHL A	8.060	5.771	2.289	600	633	698	632	544	468	298	141	66
Kaybob BHL A	17.300	15.456	1.844	915	766	641	536	449	375	220	0	0
Kaybob South Triassic A	17.600	11.575	6.025	1710	1543	1392	1255	1132	1022	750	448	267
Kakwa A Cardium A	1.499	0.374	1.125	500	504	428	343	275	221	114	38	0
Loon Field Total	1.274	0.402	0.872	301	267	236	209	186	164	114	62	34
Nipisi Gilwood A 40%	22.200	15.464	6.736	1980	2200	2200	2042	1707	1426	831	337	137
Nipisi Keg Rvr Sd A 40%	0.250	0.177	0.073	28	24	21	19	16	14	9	5	0
Nipisi Keg Rvr Sd E 40%	0.227	0.125	0.102	48	43	35	29	24	20	11	4	0
Nipisi Field Other 40%	0.380	0.253	0.127	44	44	43	38	33	28	18	1	0
Pine Creek Field Total	0.770	0.582	0.188	86	72	62	55	49	44	33	0	0
Pouce Coupe S. Bdry B	1.200	0.231	0.969	130	140	140	140	136	122	92	65	49
Progress Halfway B	0.631	0.095	0.536	180	180	169	146	125	108	69	32	15
Progress Field Other	0.447	0.076	0.371	140	126	111	96	83	73	49	27	0
Red Earth Slave Pt A	0.828	0.533	0.295	130	124	108	90	75	63	36	1	0
Red Earth Granite Wash A	4.000	2.781	1.219	280	280	263	232	205	184	135	89	62
Red Earth Field Other	3.900	2.141	1.759	384	339	303	274	249	228	181	132	103
Rycroft Charlie Lake A	0.968	0.128	0.840	270	270	267	236	201	171	106	47	21
Rycroft Halfway C&D	0.700	0.008	0.692	190	188	168	145	127	111	76	43	26
Shadow Field Total	0.595	0.031	0.564	101	133	131	121	110	99	73	44	27
Simonette D-3	6.100	5.654	0.446	202	171	145	122	103	87	53	23	0
Simonette D-3C	0.500	0.007	0.493	100	99	91	79	70	62	45	30	21
Snipe Lake BHL	10.000	8.135	1.865	600	571	505	445	393	347	238	127	68
Spirit River Halfway F	2.297	0.273	2.024	430	575	522	463	411	364	254	139	76
Sturgeon Lake D-3	3.690	3.271	0.419	130	127	114	100	88	78	53	28	15
Sturgeon Lake South D-3	25.500	19.876	5.624	2357	2011	1715	1463	1248	1064	660	298	134
Sturgeon Lake South D-3C	0.450	0.121	0.329	110	110	109	98	83	70	43	18	8
Tangent Field Total	1.700	0.413	1.287	266	226	196	173	153	138	104	72	54
Utikuma Lk KR Sand A 31%	2.476	1.560	0.916	404	385	334	274	224	183	100	37	0
Utik. Lk KR Sd NKRAA 31%	0.549	0.257	0.292	118	119	100	84	70	58	34	13	0
Utikuma Lk Fld Other 31%	0.897	0.286	0.611	137	131	121	107	96	86	64	42	30
Valhalla Doe Creek I	5.900	0.657	5.243	562	625	625	605	552	505	400	291	225
Valhalla Halfway C	0.460	0.069	0.391	165	153	128	107	89	74	43	17	7
Valhalla Field Other	0.912	0.197	0.715	207	184	164	147	133	120	90	58	39
Wapiti Cardium A&B	0.773	0.063	0.710	115	114	105	96	88	81	65	49	39
Wembley Doig E	0.180	0.074	0.106	85	61	44	31	23	16	6	0	0
Wembley Halfway B	4.200	0.842	3.358	799	709	632	566	510	461	349	232	164
Windfall D-3A	2.600	2.179	0.421	150	147	125	105	88	75	49	28	17
Miscellaneous & Undef	11.810	5.691	6.119	1405	1240	1104	991	895	813	627	438	326

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Light Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
Pipeline Total	174.228	111.206	63.022	17617	16885	15432	13719	11915	10384	7037	3792	2250
Pembina Pipeline Company Ltd												
Bigoray Cardium B	1.066	20.250	12.325	270	241	209	179	154	133	85	40	18
Bigoray Nisku B	0.900	0.585	0.338	125	124	113	101	91	81	58	33	19
Bigoray Nisku C	0.552	1.216	0.528	85	140	140	140	130	112	71	33	15
Bigoray Nisku E	0.900	5.435	1.951	93	81	72	65	59	54	43	32	26
Bigoray Nisku F	1.790	0.913	0.877	500	509	382	283	209	155	63	14	0
Bigoray Nisku G	0.460	0.225	0.235	140	121	95	74	57	45	21	0	0
Bigoray Nisku H	0.924	0.296	0.628	220	269	238	195	159	130	71	26	3
Bigoray Nisku K	0.383	0.179	0.204	115	108	89	69	54	42	20	0	0
Brazeau River Nisku A	3.980	2.408	1.572	1200	1113	777	496	316	201	52	0	0
Brazeau River Nisku B	1.840	0.666	1.174	500	523	443	359	291	236	125	44	15
Brazeau River Nisku D	1.760	0.785	0.975	380	360	355	302	248	203	111	40	8
Brazeau River Nisku E	1.500	0.889	0.611	450	432	313	199	127	81	21	0	0
Brazeau River Fld Other	1.999	0.555	1.444	320	360	360	350	313	278	194	106	58
Carrot Creek Cardium F	1.580	0.276	1.304	360	339	315	282	253	226	163	94	54
Carrot Creek Field Other	1.438	0.547	0.891	330	280	240	207	181	158	111	67	31
Crystal Viking A	5.679	1.166	4.513	800	800	800	795	725	643	465	299	208
Cyn-Pem Cardium A&B	2.334	1.984	0.350	120	112	96	81	69	59	39	22	14
Cyn-Pem Cardium D	2.170	0.312	1.858	320	550	550	523	452	389	248	117	55
Cyn-Pem Field Other	1.349	0.391	0.958	250	260	244	215	190	168	119	70	43
Highvale Lower Mann A	0.625	0.251	0.374	84	75	68	62	57	53	43	32	26
Highvale Field Other	1.451	0.376	1.075	230	218	194	175	158	143	109	75	54
Minnehik Buck Lk Fld Ttl	0.950	0.297	0.653	180	162	147	134	122	112	88	63	47
Niton Rock Creek F	1.800	1.001	0.799	138	127	117	108	100	93	76	56	43
Peco Field Total	0.946	0.348	0.598	144	131	119	108	99	91	71	48	34
Pembina Keystone BR B	8.000	6.049	1.951	430	393	361	331	304	280	220	151	106
Pembina Keystone BR C	2.782	2.082	0.700	260	247	218	188	161	139	88	41	9
Pembina Keystone BR I	1.633	0.986	0.647	96	89	83	78	74	70	60	48	40
Pembina Keystone BR M	1.630	1.054	0.576	180	161	145	130	117	105	76	44	25
Pembina Keystone BR U	2.022	1.090	0.932	173	160	148	138	129	120	99	75	59
Pembina Keystone BR X&C	1.793	0.465	1.328	115	122	130	130	130	130	119	92	74
Pembina BR FFF & GGG	0.675	0.185	0.490	115	129	120	108	97	88	64	38	22
Pembina Belly River DDD	0.950	0.130	0.820	200	219	203	182	163	146	105	60	35
Pembina Belly Rvr Other	2.581	1.156	1.425	175	165	157	149	142	136	119	98	82
Pembina Cardium	232.000	162.602	69.398	7072	6733	6416	6121	5845	5586	4900	4000	3319
Pembina Ostracod E	1.548	0.295	1.253	350	350	314	280	249	222	157	88	49
Pembina Nisku A	1.960	0.841	1.119	550	568	463	361	281	219	103	29	0
Pembina Nisku C	0.750	0.462	0.288	200	186	131	92	65	46	16	0	0
Pembina Nisku D	2.970	1.519	1.451	900	840	664	477	343	246	91	17	0
Pembina Nisku G	2.100	0.959	1.141	600	620	543	402	298	220	89	20	0
Pembina Nisku K	2.218	0.766	1.452	550	610	610	542	418	322	147	40	9
Pembina Nisku L	4.100	1.265	2.835	1100	1210	1208	1037	799	616	282	77	21
Pembina Nisku M	2.140	0.766	1.374	600	630	609	485	374	288	132	36	0
Pembina Nisku N	0.720	0.104	0.616	200	210	210	209	187	150	77	25	0
Pembina Nisku O	1.240	0.350	0.890	350	350	350	328	258	201	95	27	7

Light Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
Pembina Nisku P	3.315	0.954	2.361	950	980	979	847	660	514	242	69	19
Pembina Nisku Q	2.350	0.351	1.999	695	695	695	686	579	464	240	79	26
Westpem Nisku A	1.990	0.900	1.090	550	576	469	358	273	208	92	24	0
Westpem Nisku C	3.200	1.257	1.943	900	900	824	644	501	390	184	52	15
Westpem Nisku D	1.540	0.755	0.785	440	429	341	257	194	147	63	15	0
Pembina Pl Nisku Misc	3.669	1.452	2.217	510	510	510	509	470	417	291	159	87
Will-Green Card A 75%	20.250	12.325	7.925	861	802	751	706	665	629	540	435	363
Will-Green Viking A 75%	0.585	0.338	0.247	124	105	89	75	64	54	33	0	0
Will-Green Fld Other 75%	1.216	0.528	0.688	133	123	114	106	99	93	78	61	50
Pembina Pipeline Msc&Und	5.435	1.951	3.484	714	649	593	543	500	462	369	267	202
Pipeline Total	355.738	218.982	136.756	27447	27215	24946	22031	19079	16618	11665	7503	5412
Rainbow Pipe Line Company, Ltd.												
Amber Field Total	0.859	0.426	0.433	137	123	110	98	88	79	57	33	19
Amigo Field Total	0.586	0.260	0.326	115	107	94	82	71	62	41	21	10
Evi Granite Wash N	0.868	0.091	0.777	300	280	269	227	190	159	92	37	15
Evi Granite Wash P	0.912	0.052	0.860	310	309	266	226	193	164	101	45	20
Evi Field Other	2.117	0.670	1.447	300	310	297	268	242	219	167	112	79
Golden Slave Pt A	2.500	1.896	0.604	240	198	165	139	118	101	66	36	21
Kidney Field Total	1.073	0.041	1.032	321	287	256	228	204	182	129	73	41
Mitsue Gilwood A	63.900	41.633	22.267	4225	4800	4800	4636	4200	3801	2815	1707	1035
Nipisi Gilwood A 60%	33.300	23.195	10.105	2970	3300	3300	3064	2561	2139	1246	506	206
Nipisi Keg Rvr Sd A 60%	0.375	0.266	0.109	42	37	32	28	25	22	15	8	0
Nipisi Keg Rvr Sd E 60%	0.341	0.188	0.153	72	65	53	44	36	29	16	6	0
Nipisi Field Other 60%	0.570	0.380	0.190	66	66	64	57	49	42	26	4	0
Otter Granite Wash A	0.550	0.145	0.405	135	128	113	99	87	76	51	27	14
Otter Field Other	1.026	0.148	0.878	250	249	230	204	181	160	112	61	33
Panny Keg River D	0.500	0.138	0.362	110	106	93	80	70	61	41	23	13
Panny Field Other	1.050	0.165	0.885	310	302	263	226	195	168	107	50	23
Rainbow Muskeg C	0.994	0.313	0.681	115	160	160	159	144	125	84	47	29
Rainbow Muskeg O	0.487	0.149	0.338	118	99	84	72	62	55	38	24	16
Rainbow Keg River A	10.800	8.798	2.002	702	689	629	535	455	387	238	106	47
Rainbow Keg River B	30.470	18.727	11.743	1165	1052	958	877	809	749	611	462	368
Rainbow Keg River E	2.800	1.758	1.042	365	365	364	326	267	218	120	44	16
Rainbow Keg River F	19.100	14.953	4.147	1200	962	845	746	662	589	425	263	172
Rainbow Keg River I	3.410	2.498	0.912	155	132	115	102	91	83	64	47	37
Rainbow Keg River K	0.623	0.431	0.192	110	99	77	60	47	36	17	0	0
Rainbow Keg River N	1.150	0.667	0.483	210	192	160	134	112	93	54	22	0
Rainbow Keg River Z	1.101	0.656	0.445	280	250	185	137	101	75	30	0	0
Rainbow Keg River AA	7.300	6.500	0.800	350	331	264	211	171	141	83	40	22
Rainbow Keg River FF	1.800	1.035	0.765	470	425	316	234	173	128	52	11	0
Rainbow Keg River GG	0.893	0.410	0.483	210	163	142	118	99	83	53	27	16
Rainbow Keg River MM	0.500	0.189	0.311	80	76	63	54	47	41	30	21	16
Rainbow Keg River C2C	1.350	0.600	0.750	165	220	220	200	166	138	85	43	24
Rainbow Field Other	12.203	7.967	4.236	1200	1300	1293	1162	1000	861	549	259	122
I.S No. 1 Other	9.919	7.822	2.097	484	423	372	330	295	265	198	132	94
I.S. No. 11 Other	3.258	2.792	0.466	212	179	152	129	109	93	56	24	0

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Light Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
Rainbow South-KR B	4.200	3.324	0.876	315	315	313	272	222	182	100	36	13
Rainbow South-KR E	2.570	2.189	0.381	128	109	93	80	70	61	42	24	15
Rainbow S. Fld Other	5.979	3.931	2.048	750	770	760	649	531	435	238	87	0
Sawn Lake Slave Pt J	0.700	0.113	0.587	112	100	90	81	75	69	56	42	34
Seal Slave Pt A	0.560	0.284	0.276	140	130	106	86	70	56	30	8	0
Senex Field Total	0.714	0.045	0.669	145	170	170	161	139	121	81	44	25
Shekilie Field Total	3.600	1.992	1.608	442	378	328	287	254	227	168	112	81
Slave - Slave Pt. H	1.200	0.317	0.883	350	338	301	251	210	175	102	41	16
Slave - Slave Pt. L&S	0.950	0.337	0.613	240	234	202	170	144	121	73	31	13
Trout Keg River A	0.588	0.049	0.539	135	124	108	94	83	74	54	35	24
Utikuma Lk KR Sand A 69%	5.512	3.473	2.039	897	857	744	609	499	408	224	82	0
Utik. Lk KR Sd NKRAA 69%	1.223	0.572	0.651	262	266	225	188	157	131	76	31	0
Utikuma Lk Fld Other 69%	1.996	0.636	1.360	304	292	270	239	214	192	144	96	68
Virgo Field Total	7.692	6.010	1.682	750	697	612	503	413	340	188	70	0
Zama Field Total	14.417	11.446	2.971	897	773	674	593	526	471	349	231	165
Miscellaneous & Undef	3.277	1.651	1.626	270	269	246	219	197	178	137	97	74
Pipeline Total	273.863	182.328	91.535	23656	23624	22068	19801	17145	14888	9955	5410	3055
Rangeland Pipe Line Company												
Caroline Cardium E	2.213	1.080	1.133	420	366	319	278	243	212	140	70	35
Caroline Viking A	1.241	0.856	0.385	99	91	83	77	71	66	54	39	27
Ferrier Cardium D	3.142	1.693	1.449	280	297	274	250	228	209	163	113	82
Ferrier Cardium E	4.850	2.436	2.414	450	460	449	401	357	321	240	162	118
Ferrier Cardium G&L	3.570	1.051	2.519	575	549	511	456	409	369	278	186	132
Ferrier Field Other	1.064	0.694	0.370	109	98	89	80	73	67	51	34	4
Garrington Card A&B 73%	2.358	2.014	0.344	123	119	107	96	86	76	54	0	0
Garrington Viking A 73%	0.657	0.359	0.298	104	89	78	69	62	56	43	31	0
Garrington Fld Other 73%	1.307	0.767	0.540	197	191	166	144	125	109	74	41	0
Gilby Basal Mann. B	1.300	0.954	0.346	61	56	51	47	44	41	33	25	20
Gilby Jurassic B	3.670	2.543	1.127	185	162	144	129	118	108	86	64	51
Gilby Field Other	4.650	3.718	0.932	245	245	234	212	191	173	128	78	47
Innisfail D-3	12.800	11.375	1.425	925	837	612	444	322	234	89	0	0
Med River Viking D&M	0.885	0.322	0.563	207	176	151	131	115	101	71	44	4
Med River Glauconitic A	2.436	1.614	0.822	275	275	265	229	197	170	108	51	0
Med River Jurassic A	1.800	1.659	0.141	95	74	57	44	34	27	12	0	0
Med River Jurassic C&K	2.400	1.528	0.872	280	309	284	242	206	176	108	48	21
Med River Jurassic D	2.130	1.646	0.484	146	131	117	105	94	84	61	35	20
Med River Pekisko I	1.330	0.857	0.473	146	131	117	105	94	84	60	34	19
Med River Pekisko N	0.600	0.225	0.375	75	74	70	63	58	53	40	27	19
Med River Field Other	4.055	2.221	1.834	340	400	387	351	319	290	220	144	97
Ricinus Cardium A	2.880	1.335	1.545	306	273	245	221	201	183	143	100	74
Ricinus Field Other	3.297	1.608	1.689	400	393	353	312	278	249	184	119	82
Sundre Rundle A	5.970	4.890	1.080	400	379	326	281	242	208	132	62	29
Sylvan Lake Elk-Shun D	0.900	0.511	0.389	145	135	116	100	86	74	47	22	10
Sylvan Lake Pekisko B	2.300	1.585	0.715	260	249	215	185	159	137	87	41	19
Sylvan Lake Field Other	3.192	1.842	1.350	450	494	439	378	325	280	178	84	0
Will-Green Card A 25%	6.750	4.108	2.642	287	267	250	235	222	209	180	145	121

Light Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
Will-Green Viking A 25%	0.195	0.113	0.082	41	34	29	24	21	17	10	0	0
Will-Green Fld Other 25%	0.405	0.176	0.229	44	40	37	35	32	30	25	20	16
Wimborne D-3A	3.400	2.640	0.760	520	475	335	236	166	117	41	0	0
Miscellaneous & Undef	3.241	1.880	1.361	446	403	364	329	297	268	197	118	0
Pipeline Total	90.988	60.300	30.688	8635	8287	7292	6307	5490	4812	3356	1951	1059
Texaco Canada Inc.												
Bonnie Glen D-3A	86.000	77.282	8.718	3813	2915	2301	1863	1538	1292	826	464	297
Ferrybank Field Total	0.376	0.048	0.328	102	89	78	69	62	56	41	27	19
Glen Park D-3A	3.424	3.101	0.323	82	64	53	45	39	34	25	18	13
Westerose D-3	23.000	19.073	3.927	3000	2857	1999	1274	812	518	134	0	0
Wizard Lake D-3A	58.000	49.655	8.345	2377	1965	1599	1308	1100	945	653	419	302
Miscellaneous & Undef	1.880	1.652	0.228	110	102	86	71	60	50	29	0	0
Pipeline Total	172.680	150.811	21.869	9484	7996	6118	4633	3614	2897	1712	930	634
Trans-Prairie Pipelines Ltd.-Boundary Lake South												
Boundary L.South Tria.C	0.666	0.366	0.300	53	50	47	45	42	40	34	26	19
Boundary L.South Tria.E	3.937	2.525	1.412	345	317	291	268	246	226	176	115	76
Boundary L.South Tria.H	0.805	0.231	0.574	90	88	83	79	75	71	60	46	35
Miscellaneous & Undef	0.138	0.043	0.095	22	20	19	18	17	16	13	10	7
Pipeline Total	5.546	3.165	2.381	511	477	443	411	382	355	285	198	139
Twining Pipeline Division												
Twining-Rundle A & LM A	7.500	4.084	3.416	585	540	502	468	438	412	349	276	228
Miscellaneous & Undef	0.861	0.348	0.513	125	122	109	97	87	78	58	37	25
Pipeline Total	8.361	4.432	3.929	710	662	611	566	526	491	407	314	253
Valley Pipeline												
Turner Valley Total	25.484	21.941	3.543	422	408	394	381	369	356	322	271	229
Pipeline Total	25.484	21.941	3.543	422	408	394	381	369	356	322	271	229
Truck and Tank Car												
Truck & Tank Light	0.093	0.076	0.017	11	9	8	7	6	4	0	0	0
Pipeline Total	0.093	0.076	0.017	11	9	8	7	6	4	0	0	0
Undefined and Confidential												
Light Undef & Confid	3.100	1.100	2.000	800	781	682	587	505	435	277	0	0
Pipeline Total	3.100	1.100	2.000	800	781	682	587	505	435	277	0	0
Alberta Total	**1945.658**	**1439.667**	**505.991**	**132551**	**125977**	**112305**	**98040**	**84762**	**73797**	**50692**	**29698**	**18714**

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Light Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
Saskatchewan												
Bow River Pipeline Ltd. - Light												
Avon Hill Viking Total	0.700	0.458	0.242	102	88	78	70	63	57	45	0	0
Dodsland Eagle L Vol	3.003	1.996	1.007	219	200	184	171	159	149	124	98	81
Dodsland Gleneath Unit	2.550	1.865	0.685	181	165	151	139	128	118	94	67	50
Dodsland Viking Sand Non	3.429	2.208	1.221	549	481	428	386	351	322	251	0	0
E Dodsland Viking Vol Un	2.000	0.800	1.200	103	131	158	186	200	196	152	107	81
N Dodsland Viking Vol Un	0.900	0.173	0.727	55	75	95	115	125	121	92	62	45
Eureka Viking South Unit	1.380	1.120	0.260	75	70	64	60	55	51	40	27	0
Kerrobert Viking	2.300	0.595	1.705	655	551	473	413	365	327	246	170	0
Miscellaneous	2.514	1.858	0.656	280	287	254	219	188	162	103	0	0
Pipeline Total	18.776	11.073	7.703	2222	2051	1890	1760	1637	1506	1151	534	258
Producers Pipeline Company-Southeast Saskatchewan Light												
Alameda-Midale East Unit	1.841	1.495	0.346	66	62	58	55	52	49	41	31	23
Alida East-Unit	2.450	1.832	0.618	220	207	180	156	136	118	77	38	19
Alida West - Alida Non	2.150	1.791	0.359	100	91	83	76	69	63	48	30	19
Arcola Frobisher-Alida	1.550	0.970	0.580	152	139	127	116	106	97	74	47	29
Bienfait Midale Beds	0.539	0.183	0.356	90	83	75	69	63	57	44	28	17
Browning-Frob Alida Non	1.100	0.848	0.252	68	62	57	52	48	43	33	21	13
Carnduff -Midale E Unit	3.000	2.687	0.313	86	80	74	69	64	59	47	32	0
Elmore - Frob Vol Unit	2.075	1.719	0.356	90	83	76	70	64	58	45	29	18
Flat Lk Ratcliffe Vol Un	2.100	1.557	0.543	151	136	123	112	101	91	67	41	24
Freda Lake Ratcliffe	0.964	0.523	0.441	142	127	114	102	92	83	60	35	15
Hastings - Frob Non-Unit	2.020	1.700	0.320	115	102	91	81	72	64	45	25	0
Hastings Frobisher Other	3.162	2.691	0.471	135	123	113	103	94	86	65	41	26
Ingoldsby-Frob Vol Unit	2.500	2.205	0.295	71	64	58	53	49	44	35	24	18
Kenosee-Tilston Vol Unit	2.330	1.886	0.444	128	115	104	94	85	76	56	33	20
Moose Mountain Tilston	0.788	0.511	0.277	103	90	79	69	60	53	35	18	2
Nottingham Field Total	2.760	2.264	0.496	108	117	107	98	90	83	64	42	27
Oungre Ratcliffe	1.910	1.001	0.909	125	119	113	108	103	99	86	68	54
Parkman-Til Souris V Non	4.300	3.199	1.101	395	349	309	273	241	214	148	80	0
Queensdale East-Frob Non	6.500	4.354	2.146	526	483	442	406	372	341	263	170	110
Rosebank-Frob Vol Unit 1	3.947	3.521	0.426	86	81	75	70	66	61	50	35	25
Sherwood-Frobisher Non	1.950	1.672	0.278	80	82	73	65	57	51	35	19	10
Star Valley-Frob Ali Non	2.100	1.284	0.816	201	184	169	155	142	130	100	65	42
Steelman Frobisher Total	2.373	2.028	0.345	109	98	89	80	73	66	48	29	0
Steelman Midale Unit 1A	9.000	8.289	0.711	215	195	176	160	145	131	98	60	36
Steelman Midale Unit 2	8.800	7.741	1.059	248	228	210	194	178	164	128	85	56
Steelman Midale Unit 3	4.650	4.009	0.641	141	139	133	123	113	105	82	55	37
Steelman Midale Unit 4	5.650	4.826	0.824	215	200	183	168	155	142	110	72	47
Steelman Midale Unit 6	9.500	8.783	0.717	206	194	180	163	148	134	100	62	23
Steelman Midale Non-Unit	0.688	0.577	0.111	69	58	49	42	35	30	0	0	0
Steelman Midale Others	3.850	3.258	0.592	183	165	149	134	121	109	80	47	28
Viewfield-Frob Alida Non	0.850	0.545	0.305	87	79	71	65	58	53	39	24	14

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Light Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
White Bear Tilston Beds	1.500	0.964	0.536	150	155	139	123	109	96	67	37	20
Willmar-Frob Ali Non-Un	3.768	2.851	0.917	202	187	173	161	149	138	110	75	51
Willmar-Frob Ali Units	2.175	1.754	0.421	98	90	84	78	72	67	53	36	24
Workman-Frob Non-Unit	1.750	1.102	0.648	135	126	118	110	103	96	78	56	40
Workman-Frob Vol Unit 1	1.920	1.657	0.263	68	65	59	54	49	45	34	22	14
Miscellaneous	26.736	18.436	8.300	2700	2646	2354	2067	1815	1594	1079	563	294
Pipeline Total	135.246	106.713	28.533	8078	7623	6887	6190	5566	5007	3641	2189	1210
Saskatchewan Total	**154.022**	**117.786**	**36.236**	**10301**	**9674**	**8777**	**7950**	**7203**	**6514**	**4792**	**2723**	**1468**
Manitoba												
Trans-Prairie Pipelines Ltd.												
Daly Field Total	5.600	3.991	1.609	430	420	387	355	325	298	229	148	63
Virden Field Total	23.118	18.555	4.563	859	809	762	718	676	637	532	394	292
Waskada Field Total	4.243	1.251	2.992	600	545	499	458	422	391	316	234	181
Miscellaneous	1.611	1.051	0.560	235	195	164	140	121	106	73	45	0
Pipeline Total	34.572	24.848	9.724	2125	1972	1814	1672	1546	1433	1153	823	537
Manitoba Total	**34.572**	**24.848**	**9.724**	**2125**	**1972**	**1814**	**1672**	**1546**	**1433**	**1153**	**823**	**537**
Ontario												
Ontario All												
Ontario Total	10.261	9.357	0.904	370	354	301	254	214	181	108	46	0
Pipeline Total	10.261	9.357	0.904	370	354	301	254	214	181	108	46	0
Ontario Total	**10.261**	**9.357**	**0.904**	**370**	**354**	**301**	**254**	**214**	**181**	**108**	**46**	**0**
Canada Total	**2264.190**	**1663.500**	**600.690**	155430	147792	132445	116635	101983	89779	63122	37103	22980
Adjusted Total - Low Case				156700	149555	134200	119300	105100	92900	65400	37300	22200
Adjusted Total - High Case				156700	152700	138900	124300	110100	97700	69300	39000	22700

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Heavy Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
Alberta												
Bow River Pipe Lines Ltd.												
Alderson U.Mann Z	0.400	0.120	0.280	100	96	84	72	62	53	34	16	7
Alderson Field Other	2.781	1.500	1.281	430	429	393	345	303	266	180	94	0
Badger U. Mann B	0.656	0.047	0.609	120	120	120	119	110	101	77	49	31
Bantry Mannville D	1.200	0.802	0.398	150	141	122	105	90	78	49	23	0
Bantry Mannville A&FF	8.000	5.730	2.270	710	701	628	551	484	425	288	150	78
Bantry Field Other	0.812	0.479	0.333	160	146	122	102	85	71	41	0	0
Bow Island Glauconitic A	0.320	0.064	0.256	95	94	80	68	58	49	30	13	6
Cessford Mannville C	3.200	2.106	1.094	296	271	248	227	208	190	146	94	60
Cessford Field Other	2.948	2.237	0.711	115	124	120	113	107	101	86	67	54
Chin Coulee Bsl Mann A	0.910	0.795	0.115	69	56	47	39	33	28	0	0	0
Countess U Mann B	1.450	1.148	0.302	146	122	101	84	70	59	34	13	0
Countess U Mann D	6.300	4.900	1.400	625	527	445	376	317	268	161	69	12
Countess U Mann H	2.400	1.928	0.472	173	151	131	115	100	87	58	29	15
Countess U Mann O	1.000	0.676	0.324	125	108	93	80	69	60	38	18	8
Countess Field Other	1.014	0.732	0.282	116	101	87	76	65	57	37	18	0
Grand Forks U Mann B	1.350	0.922	0.428	100	85	73	63	56	50	37	25	18
Grand Forks L Mann D	6.230	4.595	1.635	625	596	525	443	374	315	189	81	34
Grand Forks L Mann K&V	2.040	1.550	0.490	199	164	137	115	98	83	54	29	17
Grand Forks Sawtooth L	0.500	0.152	0.348	133	106	86	72	61	52	35	20	13
Grand Forks Sawtooth N	0.290	0.077	0.213	176	123	86	60	42	29	10	0	0
Grand Forks Sawtooth O	1.150	0.370	0.780	450	399	307	237	183	141	64	17	0
Grand Forks Sawtooth S	0.420	0.272	0.148	72	58	48	39	33	27	16	8	0
Grand Forks Sawtooth T	0.670	0.331	0.339	121	100	83	70	60	51	34	19	12
Grand Forks Sawtooth MM	1.884	1.159	0.725	372	305	251	206	169	139	77	28	0
Grand Forks Sawtooth OO	1.000	0.627	0.373	151	126	107	91	77	66	43	22	12
Grand Forks Sawtooth WW	1.800	0.535	1.265	610	506	419	348	288	239	136	53	15
Grand Forks Field Other	2.657	1.130	1.527	560	542	470	405	348	300	191	90	6
Hays Lower Mann A	1.650	1.425	0.225	92	80	68	59	51	44	28	13	0
Hays Sawtooth C	0.470	0.196	0.274	123	104	87	73	62	52	31	13	5
Hays Field Other	0.479	0.219	0.260	160	127	101	80	63	50	25	0	0
Horsefly Lake Mannville	1.276	0.981	0.295	92	84	77	71	64	59	45	29	0
Jenner U Mannville O	0.350	0.100	0.250	130	118	95	76	61	49	25	0	0
Jenner Field Other	1.209	0.943	0.266	94	83	73	65	58	51	35	19	0
Lathom U Mann A	2.350	1.748	0.602	191	164	141	122	106	93	64	37	23
Little Bow Field Total	2.339	0.817	1.522	370	400	398	367	326	289	201	110	60
Medicine Hat Glauc C	0.700	0.053	0.647	230	275	236	197	164	137	80	31	0
Ronalane Field Total	0.702	0.089	0.613	180	180	173	152	134	117	79	41	21
Sibbald U Mannville C	0.920	0.290	0.630	320	291	233	187	150	120	62	20	0
Suffield Upper Mann J	0.750	0.362	0.388	431	270	170	106	67	16	0	0	0
Taber Mann D	2.500	1.827	0.673	139	128	118	109	101	94	77	58	45
Taber N. Glauc A	2.500	0.680	1.820	525	471	422	378	339	304	218	126	73
Taber N. Taber K	0.350	0.078	0.272	105	97	83	72	62	53	34	16	0

Heavy Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
Taber N. Field Other	1.968	0.930	1.038	296	256	224	197	175	156	115	75	53
Taber S. Mann A	1.200	0.949	0.251	75	77	69	63	57	51	38	23	0
Taber South Mann B	2.200	1.894	0.306	110	97	86	76	67	59	40	21	0
Turin Upper Mann C&J	0.501	0.235	0.266	111	96	82	71	61	53	34	16	0
Turin Field Other	0.456	0.308	0.148	65	57	49	43	38	33	22	0	0
Wrentham Field Total	0.678	0.482	0.196	101	86	74	63	54	46	28	0	0
Miscellaneous & Undef	5.503	3.260	2.243	800	809	704	612	532	462	304	151	0
Pipeline Total	84.433	52.850	31.583	11755	10666	9202	7883	6763	5795	3751	1863	691
BP Exploration Canada Limited												
Chauvin Mannville A	1.250	1.096	0.154	77	66	56	47	40	34	21	0	0
Chauvin Field Other	0.319	0.184	0.135	59	51	44	38	33	29	21	0	0
Chauvin South Spky E	0.950	0.567	0.383	185	178	147	119	97	78	41	0	0
Chauvin South Spky H	0.768	0.528	0.240	85	89	76	65	56	48	31	14	0
Chauvin South Spky A&B	1.690	1.211	0.479	180	168	146	127	111	97	64	32	0
Chauvin S. Field Other	1.136	0.693	0.443	180	168	147	128	112	97	65	0	0
David Lloyd C	0.600	0.223	0.377	185	174	141	114	92	75	40	2	0
Hayter Dina A 38%	0.456	0.200	0.256	183	179	121	81	54	36	3	0	0
Hayter Dina B 38%	0.260	0.134	0.126	75	61	49	40	32	26	14	0	0
Hayter Field Other 38%	0.312	0.152	0.160	49	53	50	44	38	34	23	12	0
Miscellaneous & Undef	0.936	0.633	0.303	100	115	108	93	80	69	44	0	0
Pipeline Total	8.677	5.621	3.056	1360	1304	1090	903	752	629	370	61	0
Husky Pipeline Ltd. & Murphy Manito Pipeline Ltd. Lloyd												
Hayter Dina A 62%	0.744	0.326	0.418	299	291	198	132	89	59	7	0	0
Hayter Dina B 62%	0.424	0.219	0.205	122	99	80	65	53	43	23	0	0
Hayter Field Other 62%	0.509	0.248	0.261	80	87	81	71	63	55	37	19	0
Lloydminster Sparky B	0.575	0.428	0.147	52	46	41	37	34	31	25	0	0
Lloydminster Sparky G	0.845	0.568	0.277	138	118	100	85	73	62	38	0	0
Lloydminster Sparky K	1.000	0.593	0.407	182	162	140	120	103	89	56	0	0
Lloyd Sparky C & GP A	1.400	1.178	0.222	84	72	63	55	49	45	34	8	0
Lloyd Sparky & GP C&D	3.630	2.751	0.879	182	168	156	145	135	127	105	79	62
Lloydminster Fld Other	2.837	1.666	1.171	270	269	253	233	215	199	156	105	70
Morgan Sparky A	0.375	0.167	0.208	95	94	82	67	55	45	24	0	0
Morgan Lloyd A	0.600	0.290	0.310	141	121	107	94	83	73	50	0	0
Vermillion Sparky A	0.651	0.518	0.133	43	40	37	34	32	29	25	0	0
Viking Kinsella Wain B	4.650	3.678	0.972	546	450	372	307	253	209	117	0	0
Wainwright Wain & Spk S	13.787	9.506	4.281	1294	1206	1101	983	878	784	558	316	179
Wainwright D-2A	0.225	0.091	0.134	120	85	61	41	28	19	0	0	0
Wainwright Field Other	0.768	0.268	0.500	142	127	115	105	96	88	70	51	0
Wildmere Lloyd A & Spk E	3.000	1.583	1.417	466	415	369	328	291	259	182	101	56
Miscellaneous & Undef	1.820	0.786	1.034	237	215	196	179	165	152	122	89	69
Pipeline Total	37.840	24.864	12.976	4500	4074	3559	3092	2702	2375	1636	770	437

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Heavy Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	Productive Capacity from Remaining Reserves at 31/12/86								
				1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Truck and Tank Car												
Alexis Banff A	0.700	0.366	0.334	108	96	86	77	68	61	43	24	13
Cherhill Banff F	0.413	0.118	0.295	162	132	107	87	70	57	30	0	0
Provost U Mann B	0.550	0.399	0.151	63	53	46	40	36	32	25	0	0
Provost U Mann BB	0.600	0.178	0.422	218	181	150	124	102	85	48	0	0
Provost Dina A	0.650	0.079	0.571	235	354	263	194	144	106	43	0	0
Provost Dina C	0.309	0.086	0.223	101	87	74	63	54	46	29	0	0
Provost Dina N	0.450	0.104	0.346	218	172	135	107	84	66	32	0	0
Provost Dina S	0.600	0.017	0.583	225	257	212	174	142	116	64	23	0
Provost Basal Qtz C	0.600	0.117	0.483	245	203	167	138	114	94	53	20	0
Provost Field Other	1.308	0.452	0.856	297	257	224	197	173	153	109	66	42
St. Anne Field Total	0.259	0.088	0.171	74	63	55	47	40	35	22	9	0
Miscellaneous & Undef	2.917	2.025	0.892	297	266	237	212	189	169	121	68	13
Pipeline Total	9.356	4.029	5.327	2249	2126	1762	1465	1223	1027	623	213	70
Undefined and Confidential												
Heavy Undefined & Conf	0.500	0.198	0.302	113	100	88	78	69	61	42	23	0
Pipeline Total	0.500	0.198	0.302	113	100	88	78	69	61	42	23	0
	0.000	0.000	0.000	0	0	0	0	0	0	0	0	0
Alberta Total	**140.806**	**87.562**	**53.244**	**19979**	**18272**	**15702**	**13422**	**11511**	**9889**	**6425**	**2933**	**1199**
Saskatchewan												
Husky Pipeline Ltd. SGS & Murphy Manito Pipeline Ltd. Lloyd												
Aberfeldy Spky Sd Unit	6.700	5.137	1.563	329	310	292	274	258	243	202	149	110
Aberfeldy S Spky Sd	1.650	1.470	0.180	75	66	59	52	46	40	28	0	0
Celtic GP Sand Non Unit	1.400	0.307	1.093	315	316	286	253	225	199	139	76	41
Celtic Sparky Sand Non	0.586	0.141	0.445	90	93	87	81	75	69	55	38	26
Celtic Waseca Sand Non	1.563	0.423	1.140	295	345	311	276	245	217	151	83	45
Dee Valley Waseca Non	0.988	0.333	0.655	120	120	117	109	102	96	79	57	41
Dulwich Sparky Sand	1.877	1.677	0.200	52	74	68	62	56	50	37	0	0
Edam West Mannville Sd	0.286	0.055	0.231	52	48	45	41	38	35	28	19	13
Edam West Sparky/GP	0.942	0.235	0.707	205	185	167	151	137	123	91	55	33
Edam West Waseca	0.600	0.090	0.510	135	124	113	103	94	86	66	42	26
Epping Spky & GP Non Unt	2.350	1.978	0.372	140	128	118	108	99	91	71	0	0
Epping S Spky & GP Unit	2.849	2.515	0.334	127	112	100	88	78	69	48	26	0
Epping SW Sparky Unit	1.100	0.868	0.232	71	65	59	53	49	44	33	20	0
Golden Lk North Vol Unit	1.900	1.547	0.353	100	92	85	78	72	66	51	34	0
Golden Lk North Non Unit	0.740	0.468	0.272	78	72	66	61	56	51	39	26	0
Golden Lk S Sparky Non	1.000	0.666	0.334	65	68	64	60	56	53	44	34	27
Golden Lk S Waseca Non	2.300	1.611	0.689	218	197	178	161	146	132	97	59	0
Gully Lk Waseca Vol Unit	1.206	0.747	0.459	131	119	108	98	89	80	60	37	22
Gully Lk Waseca Non Unit	1.247	0.746	0.501	160	158	142	126	112	99	69	38	0

Heavy Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	Productive Capacity from Remaining Reserves at 31/12/86								
				1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Lashburn Field Total	1.915	1.212	0.703	236	211	189	169	151	135	97	55	0
Lone Rock Sparky Sand Pl	1.650	1.285	0.365	109	99	89	81	73	66	49	30	18
Macklin Sparky Sd Non	0.430	0.351	0.079	53	42	34	27	22	17	0	0	0
Maidstone Mclaren Sand	0.503	0.159	0.344	69	64	59	55	52	48	40	30	24
Manito Lake Sparky	0.538	0.190	0.348	122	108	96	85	75	67	46	25	0
Marsden S. Field Total	1.541	0.406	1.135	230	259	248	227	207	189	144	92	58
Neilburg Mclaren Sand	1.100	0.363	0.737	220	210	188	168	151	135	97	56	32
Northminster Field Total	1.194	0.952	0.242	91	81	73	66	59	53	38	0	0
Pikes Peak Waseca Sand	2.600	1.156	1.444	653	603	524	427	348	284	154	55	0
Salt Lake Lloydminster	0.939	0.159	0.780	221	200	180	163	147	133	98	59	35
Senlac Lloydminster Sd	0.740	0.439	0.301	168	139	115	95	78	65	36	0	0
Standard Hill Waseca Sd	1.800	0.987	0.813	211	194	178	164	150	138	107	70	46
Tangleflags GP Non	2.475	1.344	1.131	300	337	308	275	245	218	154	87	49
Tangleflags Lloyd Sd Non	1.750	0.835	0.915	184	182	174	161	149	139	113	84	65
Tangleflags N. Lloyd Sd	0.550	0.234	0.316	113	100	89	80	71	63	44	25	0
Tangleflags Other	2.480	1.438	1.042	358	319	284	253	226	201	142	79	0
Miscellaneous	11.956	7.372	4.584	1797	1573	1377	1206	1056	924	620	319	0
Pipeline Total	65.445	39.896	25.549	7905	7431	6686	5954	5308	4739	3388	1871	719
Bow River Pipe Lines Ltd.-Heavy												
Cactus Lake Bakken Sand	3.100	1.268	1.832	505	458	415	377	342	310	231	142	87
Coleville Bakken Sand	9.200	6.719	2.481	550	580	559	511	467	427	326	207	132
Coleville S. Bakken Sand	0.510	0.098	0.412	76	69	63	58	53	49	40	29	23
Court Bakken Sand	0.850	0.213	0.637	224	197	172	151	132	116	78	40	20
Luseland Bakken Sand	0.521	0.143	0.378	123	110	98	88	78	70	50	29	16
N.Hoosier Bakken Sd Vol.	1.129	0.867	0.262	77	70	63	56	51	46	33	20	11
N.Hoosier Blairmore Vol	0.900	0.599	0.301	71	66	61	56	51	47	37	24	16
Plover Lake Bakken Non	0.400	0.181	0.219	105	89	74	63	53	44	26	2	0
Miscellaneous	2.954	1.579	1.375	563	487	421	364	315	273	177	85	0
Pipeline Total	19.564	11.667	7.897	2297	2127	1930	1727	1546	1385	1001	582	308
Bow River Pipe Lines Ltd.-Light Blend Heavy												
Plato Field Total	1.290	0.527	0.763	307	322	277	239	205	177	112	0	0
Smiley Dewar Viking	5.000	4.218	0.782	246	220	199	180	164	150	116	81	0
Pipeline Total	6.290	4.745	1.545	553	542	476	419	370	327	229	81	0
South Saskatchewan Pipeline Company												
Battrum Unit 1	7.100	4.767	2.333	383	430	476	487	450	416	327	219	147
Battrum Unit 2	1.737	1.233	0.504	105	104	98	89	82	75	59	42	31
Battrum Vol Unit 3	1.813	1.267	0.546	126	117	108	101	94	87	71	51	38
Battrum Unit 4	1.213	0.924	0.289	131	112	96	82	71	60	38	0	0
Beverly Cantaur Sd Non	0.531	0.416	0.115	57	48	40	34	29	24	14	0	0
Beverly U Rose. Sd Unit	1.740	1.568	0.172	68	59	52	45	39	34	23	11	0
Bone Crk U Shaun. Unit	2.600	2.306	0.294	92	96	88	78	69	61	43	23	0
Butte U Shaun Vol Unit	1.320	0.800	0.520	160	168	152	133	117	103	69	36	2

Table A7-3 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pool, Pipeline and Region

Heavy Crude Oil

	Initial Established Reserves at 31/12/86	Cumulative Production to 31/12/86	Remaining Established Reserves at 31/12/86	1987	1988	1989	1990	1991	1992	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity from Remaining Reserves at 31/12/86 (Cubic Metres per Day)								
Cantaur - Cantaur Unit	4.410	3.864	0.546	249	212	181	154	131	112	69	17	0
Cantaur L.Roseray Unit	1.840	1.570	0.270	119	101	86	73	61	52	32	14	0
Delta U.Shaun. Unit 1	2.400	2.195	0.205	88	77	67	58	51	44	29	0	0
Dollard U. Shaun Unit	13.500	12.666	0.834	308	269	235	205	178	156	103	52	26
Fosterton Main Unit	9.171	8.615	0.556	161	145	130	117	106	95	69	41	24
Gull Lake North Unit	3.300	3.013	0.287	107	94	82	72	63	55	37	19	0
Instow U. Shaunavon Unit	8.767	7.442	1.325	411	367	328	293	262	234	167	95	54
N. Premier Roseray Ttl	4.050	3.800	0.250	151	120	95	75	60	47	23	0	0
Rapdan Unit	3.450	2.566	0.884	280	265	235	209	185	164	114	62	34
S.Success - Success Unit	3.950	3.405	0.545	161	145	130	117	106	95	69	41	24
Suffield Field Total	4.000	3.116	0.884	247	224	204	185	168	152	114	70	43
Verlo Roseray Sd Unit	2.350	1.568	0.782	265	233	205	180	158	139	95	50	26
Miscellaneous	16.625	12.566	4.059	1546	1357	1191	1046	918	806	545	284	0
Pipeline Total	95.867	79.667	16.200	5224	4754	4290	3844	3407	3022	2119	1133	452
Producers Pipeline Company-Southeast Saskatchewan												
Benson Midale Unit	2.300	1.514	0.786	150	141	133	125	118	111	92	68	50
Ingoldsby Frob Alida N U	1.850	1.562	0.288	96	86	77	69	62	56	40	23	0
Innes Frobisher	2.150	1.811	0.339	106	97	88	80	73	66	50	31	0
Lost Horse Hill Frob Ali	3.400	2.771	0.629	201	212	187	164	144	127	86	44	0
Midale Central Mid Unit	19.086	15.188	3.898	904	837	776	718	665	616	489	333	227
Midale Central Mid Non U	1.760	1.217	0.543	155	143	132	121	112	103	80	53	0
Tatagwa Midale	0.600	0.274	0.326	110	98	87	78	70	62	44	25	0
Viewfield Frob Alida Non	1.188	0.626	0.562	155	141	128	117	106	97	73	45	28
Wapella-Wapella Sand	2.285	1.340	0.945	241	222	204	187	172	158	123	81	53
Weyburn Midale Unit	51.800	41.786	10.014	2204	2040	1889	1750	1620	1500	1191	811	552
Weyburn Midale Non Unit	2.541	1.363	1.178	340	352	319	287	258	232	169	100	0
Miscellaneous	17.209	11.122	6.087	2200	1940	1712	1510	1332	1175	806	431	0
Pipeline Total	106.169	80.574	25.595	6867	6316	5737	5212	4737	4308	3249	2050	912
Saskatchewan Total	**293.335**	**216.549**	**76.786**	**22849**	**21172**	**19123**	**17158**	**15370**	**13783**	**9988**	**5719**	**2393**
Manitoba												
Trans-Prairie Pipelines Ltd.												
Kirkella Field Total	0.266	0.225	0.041	25	20	16	13	10	8	4	0	0
Pipeline Total	0.266	0.225	0.041	25	20	16	13	10	8	4	0	0
Manitoba Total	**0.266**	**0.225**	**0.041**	**25**	**20**	**16**	**13**	**10**	**8**	**4**	**0**	**0**
Canada Total	**434.407**	**304.336**	**130.071**	**42853**	**39464**	**34842**	**30593**	**26893**	**23681**	**16418**	**8653**	**3593**
Adjusted Total - Low Case				**43100**	**41600**	**36300**	**32200**	**28000**	**24200**	**16000**	**7800**	**2900**
Adjusted Total - High Case				**43100**	**43600**	**40500**	**37400**	**32900**	**28400**	**17600**	**6700**	**1700**

Table A7-4
Schedule of Miscible Flood Projects Approved by ERCB

(Millions of Cubic Metres)

Year[a]	Field, Pool	Operator	Incremental Reserves	Start of Solvent Injection
1987	Harmattan East, Rundle	Shell	0.6	1988
	Judy Creek, BHL B	Esso	1.8	1988
	Mitsue, Gilwood A (third stage)	Chevron	1.6	1988
	Nipisi, Gilwood A (third stage)	Amoco	2.0	1988
	Swan Hills, Unit 1, BHL A & B (second stage)	Home	4.6	1988
	Total		**10.6**	
1988	Morinville D3B	Can. Northwest	0.5	1988
	Pembina, Nisku D (tertiary miscible)	Chevron	0.5	1989
	Kaybob, BHL A (first stage)	Chevron	1.2	1988
	Total		**2.2**	
1989	Kaybob, BHL A (second stage)	Chevron	1.0	1989
	Fenn Big Valley D2A (Connor Lobe)	Gulf	1.7	1989
	Joffre D3B	ICG	0.6	1989
	Total		**3.3**	
1990	Kaybob, BHL A (third stage)	Chevron	0.7	1991
	Virginia Hills, BHL (first stage)	Shell	2.8	1990
	Swan Hills BHL A & B (third stage)	Home	2.7	1990
	Nipisi , Gilwood A (fourth stage)	Amoco	1.6	1990
	Total		**7.8**	

Note: [a] Reserves for some projects are recognized by the NEB in the year prior to the commencement of solvent injection.

Table A7-5
Historical Data and Projections
Oil-Directed Exploratory Drilling and Reserves Additions of
Conventional Crude Oil By Primary Recovery - Conventional Areas

	Drilling (Millions of Metres)		Reserves Added (Millions of Cubic Metres)		Additions Rate (Cubic Metres per Metre)	
1965	1.32		79.2		60.0	
1966	1.20		142.5		118.7	
1967	1.23		61.5		50.0	
1968	1.32		86.1		65.2	
1969	1.33		3.1		2.3	
1970	0.58		0.0		0.0	
1971	0.65		33.8		52.0	
1972	0.49		7.9		16.1	
1973	0.56		3.4		6.0	
1974	0.38		10.8		28.4	
1975	0.32		11.6		36.1	
1976	0.41		12.7		31.0	
1977	0.57		21.1		37.1	
1978	0.93		25.4		27.3	
1979	1.33		21.2		15.9	
1980	1.77		2.4		1.3	
1981	1.58		37.7		23.9	
1982	1.57		52.0		33.1	
1983	1.67		46.8		28.0	
1984	2.51		83.5		33.3	
1985	3.07		43.4		14.1	
1986	1.67		49.4		29.6	
	Low Case	**High Case**	**Low Case**	**High Case**	**Low Case**	**High Case**
1987	1.89	1.89	36.4	36.4	19.3	19.3
1988	1.62	1.95	29.0	34.7	17.9	17.8
1989	1.59	2.10	26.6	34.4	16.7	16.4
1990	1.48	2.37	23.3	35.4	15.7	14.9
1991	1.49	2.46	22.0	33.2	14.8	13.5
1992	1.41	2.44	19.7	29.8	14.0	12.2
1995	1.06	1.46	12.8	14.0	12.1	9.6
2000	1.03	0.92	10.0	7.0	9.7	7.6
2005	0.97	0.65	7.7	4.3	7.9	6.6

Note: The historical reserves additions may include some portion of reserves attributable to secondary recovery.

Table A7-6
Incremental Direct Costs for Crude Oil
Western Canada[a]

Reserves Additions Increment [b] (Millions of Cubic Metres)	**Low Case** ($C 1987 per Cubic Metre)	**High Case**
0 - 50	81.19	117.61
50 - 100	87.76	127.65
100 - 150	95.48	139.58
150 - 200	104.84	154.17
200 - 250	116.64	172.73
250 - 300	135.04	201.37
300 - 350	172.00	257.19

Notes: [a] Incremental direct costs includes both light and heavy crude oil.
[b] Recoverable by primary mechanisms.

Table A7-7
Annual Reserves Additions of Conventional Light Crude Oil
Conventional Areas

(Millions of Cubic Metres)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Waterflood	5.0	4.0	4.0	3.5	3.5	3.0	3.0	3.0	2.0
Miscible	10.8	2.0	4.0	4.0	3.0	3.0	3.0	3.0	3.0
Chemical	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	15.8	6.0	8.0	7.5	6.5	6.0	6.0	6.0	5.0
Discoveries	28.4	23.0	21.6	19.3	18.6	17.1	12.6	11.3	10.2
Total	**44.2**	**29.0**	**29.6**	**26.8**	**25.1**	**23.1**	**18.6**	**17.3**	**15.2**

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Waterflood	5.0	6.0	5.0	4.0	3.5	3.0	3.0	3.0	2.0
Miscible	10.8	2.0	5.0	5.0	6.0	6.0	5.0	3.0	2.0
Chemical	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0
Subtotal	15.8	8.0	10.0	9.0	9.5	9.0	8.0	7.0	5.0
Discoveries	28.4	27.4	27.5	28.6	27.2	25.0	14.1	9.8	8.3
Total	**44.2**	**35.4**	**37.5**	**37.6**	**36.7**	**34.0**	**22.1**	**16.8**	**13.3**

Notes: [a] For the waterflood, miscible and chemical categories the reserves additions are those which result from enhanced recovery in established pools discovered prior to 31 December 1986.
[b] For the discovery category the additions are those which result from new discoveries, enhanced recovery of these discoveries and appreciation other than by enhanced recovery for pools discovered prior to 31 December 1986.

Table A7-8
Annual Reserves Additions of Conventional Heavy Crude Oil
Conventional Areas

(Millions of Cubic Metres)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Waterflood	4.0	4.0	3.0	2.0	2.0	2.0	2.0	1.0	0.0
Thermal	0.0	0.0	0.0	0.0	0.5	0.7	1.3	1.7	2.0
Subtotal	4.0	4.0	3.0	2.0	2.5	2.7	3.3	2.7	2.0
Discoveries	8.1	6.8	6.6	6.1	6.1	5.8	4.6	4.5	4.3
Total	**12.1**	**10.8**	**9.6**	**8.1**	**8.6**	**8.5**	**7.9**	**7.2**	**6.3**

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Waterflood	4.0	5.0	4.0	3.0	2.0	2.0	2.0	1.0	0.0
Thermal	0.0	0.5	1.1	1.3	1.5	1.7	2.2	3.0	3.5
Subtotal	4.0	5.5	5.1	4.3	3.5	3.7	4.2	4.0	3.5
Discoveries	8.1	8.1	8.4	9.1	9.1	8.7	5.4	3.9	3.3
Total	**12.1**	**13.6**	**13.5**	**13.4**	**12.6**	**12.4**	**9.6**	**7.9**	**6.8**

Notes: [a] For the waterflood, miscible and chemical categories the reserves additions are those which result from enhanced recovery in established pools discovered prior to 31 December 1986.
[b] For the discovery category the additions are those which result from new discoveries, enhanced recovery of these discoveries and appreciation other than by enhanced recovery for pools discovered prior to 31 December 1986.

Table A7-9
Ultimate Technical Potential and Summary of Reserves Additions of Conventional Crude Oil
Conventional Areas

(Millions of Cubic Metres)	Light	Heavy	Total
Initial Established Reserves at 31 December 1986	**2264**	**434**	**2699**
Remaining Technical Potentials:			
Appreciation from EOR in Established Pools			
Waterflood	80	90	170
Miscible	200	-	200
Thermal	-	265	265
Chemical	15	15	30
Total-EOR	295	370	665
New Discoveries & Other Appreciation	563	250	813
Total Remaining Technical Potential	**858**	**620**	**1478**
Ultimate Technical Potential	**3122**	**1054**	**4177**

Reserves Additions (1987-2005)

Low Case

	Light	Heavy	Total
Appreciation from EOR in Established Pools			
Waterflood	57	30	87
Miscible	66	-	66
Thermal	-	22	22
Chemical	0	0	0
Total-EOR	123	52	175
New Discoveries & Other Appreciation	281	98	379
Total Reserves Additions (1987-2005)	**404**	**150**	**554**

High Case

	Light	Heavy	Total
Appreciation from EOR in Established Pools			
Waterflood	61	35	96
Miscible	85	-	85
Thermal	-	42	42
Chemical	8	0	8
Total-EOR	153	77	230
New Discoveries & Other Appreciation	315	110	425
Total Reserves Additions (1987-2005)	**468**	**186**	**655**

Notes: [a] The remaining technical potential of light crude oil from new discoveries and other appreciation is based on the 1988 Geological Survey of Canada's median estimate.
[b] The technical potential estimates are based on known technology.
[c] Numbers may not add due to rounding.

Table A7-10
Productive Capacity from Reserves Additions of Conventional Light Crude Oil
Conventional Areas

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Waterflood	0.0	0.5	1.3	2.1	2.8	3.5	5.3	6.8	6.8
Miscible	0.0	0.4	1.5	2.0	2.6	3.2	4.2	5.4	6.2
Chemical	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	0.0	0.9	2.8	4.1	5.4	6.7	9.5	12.2	13.0
Discoveries	3.2	9.4	15.1	20.4	24.7	28.0	32.5	32.8	31.2
Total	**3.2**	**10.2**	**18.0**	**24.5**	**30.2**	**34.7**	**42.0**	**45.0**	**44.3**

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Waterflood	0.0	0.5	1.5	2.5	3.4	4.2	6.0	7.2	7.0
Miscible	0.0	0.4	1.5	2.0	2.8	3.6	5.9	8.2	8.2
Chemical	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.0
Subtotal	0.0	0.9	3.0	4.6	6.2	7.8	11.9	15.6	16.2
Discoveries	3.2	9.9	16.9	24.0	30.6	35.9	43.1	37.8	31.5
Total	**3.2**	**10.7**	**19.9**	**28.6**	**36.8**	**43.6**	**55.0**	**53.4**	**47.7**

Basic assumptions for converting reserves additions to productive capacity.

	Delay	Initial RLI	Percent Decline in RLI	Final RLI
Waterflood	1.0	15.0	10.0	8.0
Miscible	1.3	20.0	10.0	15.0
Chemical	1.3	20.0	10.0	10.0
Discoveries	0.0	12.0	15.0	8.0

The "Delay" is the time in years from booking the reserves to first production.
The "Initial RLI" is the reserves life index (RLI) at the start of production.
The "Percent Decline in RLI" is the rate of deline of the RLI.
The "Final RLI" is the RLI during the declining production phase of the reservoir life.

Table A7-11
Productive Capacity from Reserves Additions of Conventional Heavy Crude Oil
Conventional Areas

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Waterflood	0.0	0.4	1.1	1.8	2.3	2.7	3.9	4.2	3.2
Thermal	0.0	0.0	0.0	0.0	0.0	0.1	0.7	2.1	3.3
Subtotal	0.0	0.4	1.1	1.8	2.3	2.8	4.6	6.3	6.5
Discoveries	1.0	2.9	4.8	6.6	8.1	9.3	11.2	11.9	12.0
Total	**1.0**	**3.3**	**5.9**	**8.4**	**10.4**	**12.1**	**15.8**	**18.2**	**18.4**

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Waterflood	0.0	0.4	1.2	2.1	2.8	3.3	4.5	4.6	3.7
Thermal	0.0	0.0	0.1	0.3	0.6	0.9	2.0	3.9	5.7
Subtotal	0.0	0.4	1.3	2.4	3.4	4.2	6.5	8.5	9.4
Discoveries	1.0	3.1	5.3	7.8	10.1	12.2	15.4	13.8	11.7
Total	**1.0**	**3.5**	**6.6**	**10.1**	**13.5**	**16.4**	**21.8**	**22.3**	**21.2**

Basic assumptions for converting reserves additions to productive capacity.

	Delay	Initial RLI	Percent Decline in RLI	Final RLI
Waterflood	1.0	15.0	10.0	8.0
Thermal	1.0	10.0	0.0	10.0
Discoveries	0.0	11.0	15.0	7.0

The "Delay" is the time in years from booking the reserves to first production.
The "Initial RLI" is the reserves life index (RLI) at the start of production.
The "Percent Decline in RLI" is the rate of deline of the RLI.
The "Final RLI" is the RLI during the declining production phase of the reservoir life.

Table A7-12
Productive Capacity from In Situ Bitumen Projects

(Thousands of Cubic Metres per Day)

		1987	1988	1989	1990	1995	2000	2005
Currently Approved	Low Case	13.0	16.1	19.7	24.2	24.2	21.2	23.3
Commercial Projects [a]	High Case	13.0	16.7	21.7	31.4	53.1	63.1	66.2
Currently Approved	Low Case	5.4	4.0	5.5	6.0	6.0	10.6	16.1
Experimental Projects [b]	High Case	5.4	4.0	5.6	6.1	18.2	21.6	21.1
Future Projects	Low Case	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	High Case	0.0	0.0	0.2	0.5	1.0	2.0	5.0
Total Projects	Low Case	18.4	20.1	25.2	30.2	30.2	31.8	39.4
	High Case	18.4	20.7	27.5	38.0	72.3	86.7	92.3

[a] Currently Approved Commercial Projects :

Amoco	Lindbergh
BP	Wolf Lake
Dome	Lindbergh
	Primrose
Esso	Cold Lake
Murphy	Lindbergh
PanCan.	Lindbergh
Suncor	Primrose
Shell	Cadotte Lake

[b] Currently Approved Experimental Projects:

Athabasca Area

AEC	Ipiatik Lake
Amoco	Gregoire Lake
	Brintnell
Canterra	Kearl Lake
Gulf	Hoole
	Pelican Lake
Petro Canada	Hangingstone
Unocal	Buffalo Creek
	Mclean

Cold Lake Area

Amoco	Beaverdam
BP	Marguerite Lake
Bow Valley	Marie
Cdn. Occidental	Manatokan
Esso	May-Ethel
	Leming
Excel	Ardmore
Husky	Tucker Lake
Koch	Fort Kent
Mobil	Wolf Lake
Murphy	Lindbergh
Suncor	Fort Kent
Westmin	Lindbergh

Table A7-13
Synthetic and Frontier Crude Oil Supply

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Synthetic									
Mining Plants [a]	28.5	28.8	30.5	31.2	32.5	33.9	34.9	35.1	35.1
Mining Plants [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Co-op Upgrader	0.0	1.0	7.0	8.0	8.0	8.0	8.0	8.0	8.0
Bi-Provincial Upgrader	0.0	0.0	0.0	0.0	0.0	3.5	7.0	7.0	7.0
Third Upgrader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	28.5	29.8	37.5	39.2	40.5	45.4	49.9	50.1	50.1
Frontier									
East Coast	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	13.0
Beaufort Sea	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Arctic Islands	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Subtotal	0.3	0.1	0.1	0.1	0.1	0.1	0.1	10.0	13.0
Total	**28.8**	**29.9**	**37.6**	**39.3**	**40.6**	**45.5**	**50.0**	**60.1**	**63.1**

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Synthetic									
Mining Plants [a]	28.5	28.8	30.5	31.2	32.5	34.0	35.0	35.0	35.0
Mining Plants [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.2	30.2
Co-op Upgrader	0.0	1.0	7.0	8.0	8.0	8.0	8.0	8.0	8.0
Bi-Provincial Upgrader	0.0	0.0	0.0	0.0	0.0	3.5	7.0	7.0	7.0
Third Upgrader	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	10.0
Subtotal	28.5	29.8	37.5	39.2	40.5	45.5	50.0	73.2	90.2
Frontier									
East Coast	0.1	0.0	0.0	0.0	0.0	1.5	13.4	25.0	25.0
Beaufort Sea	0.2	0.0	0.0	1.9	1.9	1.9	2.0	24.0	24.0
Arctic Islands	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Subtotal	0.4	0.1	0.1	2.0	2.0	3.5	15.5	49.0	49.0
Total	**28.9**	**29.9**	**37.6**	**41.2**	**42.5**	**49.0**	**65.5**	**122.2**	**139.2**

Notes: [a] Currently operating mining plants including expected efficiency upgrading and debottlenecking.
[b] Future mining plants, either from major expansion of existing facilities and / or new mining operations.

Table A7-14
Historical Data - Production of Crude Oil and Equivalent - Conventional Areas

(Thousands of Cubic Metres per Day)

	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977
Conventional Light	132.2	148.4	166.1	176.9	203.6	242.3	230.0	194.7	174.1	169.3
Conventional Heavy	30.1	29.4	31.2	31.8	32.3	35.2	30.3	25.2	24.6	30.8
Synthetic	2.3	4.4	5.2	6.7	8.1	8.0	7.3	6.8	7.6	7.2
Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	1.2
Pentanes plus [a]	14.4	16.8	19.2	20.4	26.5	27.0	25.7	24.1	21.3	21.1
Total	**179.0**	**199.0**	**221.7**	**235.8**	**270.5**	**312.5**	**293.3**	**250.8**	**228.8**	**229.6**

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Conventional Light	165.6	188.7	173.7	154.5	150.7	153.3	164.5	159.8	149.3	152.2
Conventional Heavy	32.2	31.8	31.1	27.9	28.7	33.0	37.6	39.1	39.9	43.1
Synthetic	8.9	14.6	20.3	17.7	19.1	25.4	21.1	26.7	29.4	28.7
Bitumen	1.2	1.5	1.5	2.0	3.2	4.0	5.3	8.1	14.8	18.4
Pentanes plus [a]	18.9	18.8	17.0	16.2	15.9	14.8	15.5	16.4	16.5	17.6
Total	**226.8**	**255.4**	**243.6**	**218.3**	**217.6**	**230.5**	**244.0**	**250.1**	**249.9**	**260.0**

Note: [a] Includes field condensate.

Table A7-15
Productive Capacity of Crude Oil and Equivalent - Total Canada

(Thousands of Cubic Metres per Day)

Low Case

	Light								Heavy						
	Light Estab-lished	Light Addi-tions	Pentanes Plus [a]	Mining Syn-thetic	Upgraded Heavy	Frontier	Diluent [b]	Light Total	Heavy Estab-lished	Heavy Addi-tions	Bitumen	Diluent	Upgrader Feed-stock	Heavy Total	Total Crude & Equiv-alent
1987	156.7	3.2	17.6	28.5	0.0	0.3	-11.7	194.6	43.1	1.0	18.4	11.7	0.0	74.2	268.8
1988	149.5	10.2	18.3	28.8	1.0	0.1	-12.4	195.5	41.6	3.3	20.1	12.4	-1.0	76.4	271.9
1989	134.2	18.0	17.9	30.5	7.0	0.1	-14.2	193.5	36.3	5.9	25.2	14.2	-7.0	74.6	268.1
1990	119.3	24.5	17.2	31.2	8.0	0.1	-16.2	184.2	32.2	8.4	30.2	16.2	-8.0	79.0	263.1
1991	105.1	30.2	17.3	32.5	8.0	0.1	-15.3	177.9	28.0	10.4	30.8	15.3	-8.0	76.5	254.4
1992	92.9	34.7	16.9	33.9	11.5	0.1	-14.0	176.0	24.2	12.1	30.3	14.0	-11.5	69.1	245.1
1993	82.5	38.1	16.7	34.9	15.0	0.1	-13.0	174.3	20.9	13.6	30.9	13.0	-15.0	63.4	237.7
1994	73.5	40.4	16.6	34.9	15.0	0.1	-12.7	167.8	18.3	14.8	30.5	12.7	-15.0	61.3	229.1
1995	65.4	42.0	16.4	34.9	15.0	0.1	-12.5	161.3	16.0	15.7	30.2	12.5	-15.0	59.4	220.7
1996	58.1	43.1	16.2	35.0	15.0	2.5	-12.3	157.6	14.0	16.5	30.2	12.3	-15.0	58.0	215.6
1997	51.9	43.8	15.9	35.0	15.0	7.0	-12.5	156.1	12.1	17.1	30.9	12.5	-15.0	57.6	213.7
1998	46.6	44.4	15.7	35.0	15.0	8.0	-12.4	152.3	10.4	17.6	30.9	12.4	-15.0	56.3	208.6
1999	41.6	44.7	17.3	35.0	15.0	8.0	-12.4	149.2	9.0	17.9	31.3	12.4	-15.0	55.6	204.8
2000	37.3	45.0	17.9	35.1	15.0	10.0	-12.6	147.7	7.8	18.2	31.8	12.6	-15.0	55.4	203.1
2001	33.7	45.1	19.2	35.1	15.0	13.0	-13.8	147.3	6.7	18.4	35.0	13.8	-15.0	58.9	206.2
2002	30.3	45.1	19.2	35.1	15.0	13.0	-14.3	143.4	5.5	18.6	36.4	14.3	-15.0	59.8	203.2
2003	27.2	44.9	19.2	35.1	15.0	13.0	-14.8	139.6	4.5	18.6	37.8	14.8	-15.0	60.7	200.3
2004	24.7	44.6	19.2	35.1	15.0	13.0	-14.9	136.7	3.6	18.5	38.2	14.9	-15.0	60.2	196.9
2005	22.2	44.3	19.2	35.1	15.0	13.0	-15.3	133.5	2.9	18.4	39.4	15.3	-15.0	61.0	194.5

Notes :
[a] Includes condensate.
[b] Approximately four thousand cubic metres per day of pentanes plus are not available as heavy oil diluent.
This volume increases beginning in 1999 when frontier production commences.
Diluent requirements in excess of the supply of pentanes plus are assumed to be met by a light oil fraction.

Table A7-15 (Continued)
Productive Capacity of Crude Oil and Equivalent - Total Canada

(Thousands of Cubic Metres per Day)

High Case

	Light								Heavy						
	Light Estab-lished	Light Addi-tions	Pentanes Plus [a]	Mining Syn-thetic	Upgraded Heavy	Frontier	Diluent [b]	Light Total	Heavy Estab-lished	Heavy Addi-tions	Bitumen	Diluent	Upgrader Feed-stock	Heavy Total	Total Crude & Equiv-alent
1987	156.7	3.2	17.6	28.5	0.0	0.3	-11.7	194.6	43.1	1.0	18.4	11.7	0.0	74.2	268.8
1988	152.7	10.7	18.5	28.8	1.0	0.1	-12.9	198.9	43.6	3.5	20.7	12.9	-1.0	79.7	278.6
1989	138.9	19.9	18.3	30.5	7.0	0.1	-15.7	199.0	40.5	6.6	27.5	15.7	-7.0	83.3	282.3
1990	124.3	28.6	17.8	31.2	8.0	2.0	-20.2	191.7	37.4	10.1	38.0	20.2	-8.0	97.7	289.4
1991	110.0	36.8	18.1	32.5	8.0	2.0	-21.1	186.3	32.9	13.5	42.7	21.1	-8.0	102.2	288.5
1992	97.7	43.6	17.8	34.0	11.5	3.5	-20.7	187.4	28.4	16.4	44.3	20.7	-11.5	98.3	285.7
1993	87.1	49.1	17.6	35.0	15.0	8.0	-22.3	189.5	24.4	18.8	51.0	22.3	-15.0	101.5	291.0
1994	77.8	52.9	17.5	35.0	15.0	10.0	-25.7	182.5	20.8	20.6	59.4	25.7	-15.0	111.5	294.0
1995	69.3	55.0	17.5	35.0	15.0	15.5	-30.9	176.4	17.6	21.8	72.3	30.9	-15.0	127.6	304.0
1996	61.6	55.8	17.3	38.8	15.0	30.0	-33.0	185.5	14.8	22.5	77.8	33.0	-15.0	133.1	318.6
1997	54.9	55.6	17.2	44.4	15.0	36.0	-34.2	188.9	12.2	22.7	81.1	34.2	-15.0	135.2	324.1
1998	49.1	55.0	17.0	46.3	17.0	49.0	-34.4	199.0	10.1	22.7	84.3	34.4	-17.0	134.5	333.5
1999	43.7	54.2	18.7	46.3	23.0	49.0	-32.1	202.8	8.2	22.5	85.3	32.1	-23.0	125.1	327.9
2000	39.0	53.4	19.5	48.2	25.0	49.0	-31.7	202.4	6.7	22.3	86.7	31.7	-25.0	122.4	324.8
2001	35.0	52.5	20.5	53.9	25.0	49.0	-32.7	203.2	5.3	22.2	89.3	32.7	-25.0	124.5	327.7
2002	31.4	51.4	20.3	57.7	25.0	49.0	-33.0	201.8	4.1	22.0	90.4	33.0	-25.0	124.5	326.3
2003	28.1	50.2	20.1	57.7	25.0	49.0	-33.0	197.1	3.1	21.7	90.8	33.0	-25.0	123.6	320.7
2004	25.3	49.0	21.3	59.6	25.0	49.0	-33.0	196.2	2.3	21.5	91.1	33.0	-25.0	122.9	319.1
2005	22.7	47.7	22.1	65.2	25.0	49.0	-33.5	198.2	1.7	21.2	92.3	33.5	-25.0	123.7	321.9

Notes :
[a] Includes condensate.
[b] Approximately four thousand cubic metres per day of pentanes plus are not available as heavy oil diluent. This volume increases beginning in 1999 when frontier production commences. Diluent requirements in excess of the supply of pentanes plus are assumed to be met by a light oil fraction.

Table A7-16
Refinery Feedstock Requirements and Sources - Canada and Regions

Canada
Low Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	80654	82990	83581	83582	84584	85472	89034	91262	94930
Deduct Product Imports	(8200)	(7306)	(8353)	(8759)	(8726)	(10281)	(13821)	(15392)	(18403)
Add Product Exports	9846	13291	12484	12660	12413	12413	12363	12363	12363
Net Regional Transfers -In/+Out	0	0	0	0	0	0	0	0	0
Product Inventory +Build/-Draw	(1266)	(1108)	(134)	165	(265)	441	276	506	0
Add Own Consumption	5020	5418	5458	5465	5536	5597	5833	6001	6237
Total	**86104**	**93284**	**93036**	**93113**	**93542**	**93642**	**93685**	**94740**	**95126**
Per Day	235.9	254.9	254.9	255.1	256.3	255.9	256.7	258.9	260.6
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	18.4	17.8	18.1	18.0	18.0	20.0	22.0	21.2	22.1
Light	143.5	149.5	149.3	149.2	150.4	148.1	147.0	140.7	126.5
Imports	64.7	73.9	75.5	75.9	75.9	75.8	77.3	86.6	101.9
Inventory Change	(1.4)	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	225.2	242.1	242.9	243.1	244.3	243.9	246.3	248.5	250.5
Partially Processed Oil and Other Material	8.1	9.7	9.3	9.3	9.3	9.3	7.7	7.7	7.5
Gas Plant Butanes	2.6	3.0	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Total	**235.9**	**254.9**	**254.9**	**255.1**	**256.3**	**255.9**	**256.7**	**258.9**	**260.6**

High Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	80654	81806	82074	82823	84307	85342	87678	92380	96327
Deduct Product Imports	(8200)	(6099)	(6480)	(7324)	(8026)	(8816)	(11477)	(14995)	(18083)
Add Product Exports	9846	13332	12484	12530	12133	12133	12083	12083	12083
Net Regional Transfers -In/+Out	0	0	0	0	0	0	0	0	0
Product Inventory +Build/-Draw	(1266)	(784)	(347)	98	112	48	570	585	0
Add Own Consumption	5020	5351	5376	5439	5545	5622	5799	6130	6401
Total	**86104**	**93605**	**93107**	**93566**	**94071**	**94329**	**94652**	**96182**	**96728**
Per Day	235.9	255.8	255.1	256.3	257.7	257.7	259.3	262.8	265.0
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	18.4	17.8	18.1	18.6	19.1	20.5	23.0	24.7	25.7
Light	143.5	150.7	148.7	149.5	150.3	150.5	161.7	175.2	176.6
Imports	64.7	73.9	76.3	76.3	76.3	74.7	62.6	50.9	50.7
Inventory Change	(1.4)	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	225.2	243.3	243.1	244.4	245.8	245.8	247.3	250.8	253.0
Partially Processed Oil and Other Material	8.1	9.7	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Gas Plant Butanes	2.6	2.7	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Total	**235.9**	**255.8**	**255.1**	**256.3**	**257.7**	**257.7**	**259.3**	**262.8**	**265.0**

Note: [a] 1987 based on actual Stats. Canada Catalogue 45-004.
[b] Domestic Demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Atlantic

Low Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	10314	10800	11126	11087	11356	11581	12933	12244	13053
Deduct Product Imports	(2207)	(2635)	(2460)	(2718)	(2985)	(3335)	(4479)	(3926)	(4811)
Add Product Exports	3184	7154	6314	6490	6243	6243	6193	6193	6193
Net Regional Transfers -In/+Out	571	1065	1175	1156	1393	1410	1356	1390	1482
Product Inventory +Build/-Draw	(191)	(267)	(106)	35	26	164	(70)	112	0
Add Own Consumption	641	719	741	740	758	773	857	822	873
Total	**12312**	**16836**	**16790**	**16790**	**16790**	**16836**	**16790**	**16836**	**16790**
Per Day	33.7	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Feedstock Sources (Thousands Of Cubic Metres per Day)									
Domestic: Heavy	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0
Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	13.0
Imports	34.3	44.8	45.6	46.0	46.0	46.0	46.0	36.0	33.0
Inventory Change	(1.0)	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	33.7	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Partially Processed Oil and Other Material	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas Plant Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**33.7**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**

High Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	10314	10086	10198	10657	11563	11904	12292	13018	12574
Deduct Product Imports	(2207)	(1747)	(1564)	(2333)	(3221)	(3574)	(3973)	(4625)	(4319)
Add Product Exports	3184	7154	6314	6490	6243	6243	6193	6193	6193
Net Regional Transfers -In/+Out	571	1065	1175	1156	1393	1410	1356	1390	1482
Product Inventory +Build/-Draw	(191)	(400)	(20)	104	38	55	94	(20)	0
Add Own Consumption	641	677	687	717	774	797	828	881	860
Total	**12312**	**16836**	**16790**	**16790**	**16790**	**16836**	**16790**	**16836**	**16790**
Per Day	33.7	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
Light	0.0	0.0	0.0	0.0	0.0	1.5	13.4	25.0	25.0
Imports	34.3	44.8	45.6	45.6	45.6	44.1	32.1	20.5	20.5
Inventory Change	(1.0)	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	33.7	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Partially Processed Oil and Other Material	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas Plant Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**33.7**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**

Note: [a] 1987 based on actual Stats. Canada Catalogue 45-004.
[b] Domestic Demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A7-16 (Continued)
Refinery Feedstocks Requirements and Sources - Canada and Regions

Quebec

Low Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	17382	17579	17782	17883	18178	18398	18998	19472	20136
Deduct Product Imports	(4137)	(1916)	(2529)	(2563)	(2808)	(3038)	(3781)	(4284)	(5491)
Add Product Exports	1107	935	940	940	940	940	940	940	940
Net Regional Transfers -In/+Out	308	(133)	(405)	(401)	(501)	(505)	(412)	(401)	138
Product Inventory +Build/-Draw	86	(554)	65	(15)	18	67	39	79	0
Add Own Consumption	876	925	937	946	963	974	1006	1030	1067
Total	**15450**	**16836**	**16790**	**16790**	**16790**	**16836**	**16790**	**16836**	**16790**
Per Day	42.3	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	2.8	1.4	1.5	1.5	1.5	1.6	1.7	0.0	0.0
Light	10.5	15.6	15.0	15.0	15.0	15.0	15.0	0.0	0.0
Imports	27.6	26.9	27.7	27.7	27.7	27.7	29.2	45.9	45.9
Inventory Change	(0.4)	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	40.5	44.4	44.2	44.2	44.2	44.3	45.9	45.9	45.9
Partially Processed Oil and Other Material	1.8	1.6	1.8	1.8	1.8	1.7	0.1	0.1	0.1
Gas Plant Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**42.3**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**

High Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	17382	17392	17531	17624	17821	17979	18406	19368	20145
Deduct Product Imports	(4137)	(1813)	(2102)	(2330)	(2424)	(2575)	(3211)	(4201)	(5504)
Add Product Exports	1107	945	940	940	940	940	940	940	940
Net Regional Transfers -In/+Out	308	(133)	(405)	(401)	(501)	(505)	(412)	(401)	138
Product Inventory +Build/-Draw	86	(470)	(97)	25	11	45	92	102	0
Add Own Consumption	876	915	923	933	943	952	975	1028	1071
Total	**15450**	**16836**	**16790**	**16790**	**16790**	**16836**	**16790**	**16836**	**16790**
Per Day	42.3	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	2.8	1.4	1.5	1.5	1.5	1.6	1.7	1.8	2.0
Light	10.5	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Imports	27.6	26.9	27.7	27.7	27.7	27.7	27.5	27.5	27.2
Inventory Change	(0.4)	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	40.5	44.4	44.2	44.2	44.2	44.3	44.2	44.3	44.2
Partially Processed Oil and Other Material	1.8	1.6	1.8	1.8	1.8	1.7	1.8	1.7	1.8
Gas Plant Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**42.3**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**	**46.0**

Note: [a] 1987 based on actual Stats. Canada Catalogue 45-004.
[b] Domestic Demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Ontario

Low Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	27241	28065	28465	28816	29449	30047	31654	33390	34300
Deduct Product Imports	(1376)	(2305)	(2825)	(2943)	(2423)	(3434)	(5117)	(6771)	(7592)
Add Product Exports	3305	3060	3060	3060	3060	3060	3060	3060	3060
Net Regional Transfers -In/+Out	(1861)	(1791)	(1752)	(1853)	(1870)	(1901)	(2044)	(2109)	(2231)
Product Inventory +Build/-Draw	(1326)	(10)	(41)	164	(292)	189	199	126	0
Add Own Consumption	2048	2261	2293	2320	2371	2418	2543	2682	2757
Total	**28031**	**29280**	**29200**	**29565**	**30295**	**30378**	**30295**	**30378**	**30295**
Per Day	76.8	80.0	80.0	81.0	83.0	83.0	83.0	83.0	83.0
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	10.5	11.7	11.9	12.2	12.2	13.7	15.1	15.7	16.2
Light	61.0	63.1	63.2	63.9	65.9	64.4	63.0	59.8	41.0
Imports	2.7	2.2	2.2	2.2	2.2	2.2	2.2	4.8	23.1
Inventory Change	(0.1)	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	74.1	76.7	77.3	78.3	80.3	80.3	80.3	80.3	80.3
Partially Processed Oil and Other Material	2.6	3.1	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Gas Plant Butanes	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**76.8**	**80.0**	**80.0**	**81.0**	**83.0**	**83.0**	**83.0**	**83.0**	**83.0**

High Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	27241	27812	28121	28502	28985	29542	30830	32610	34687
Deduct Product Imports	(1376)	(2160)	(2374)	(2286)	(1996)	(2312)	(3954)	(5796)	(7741)
Add Product Exports	3305	3062	3060	2930	2780	2780	2780	2780	2780
Net Regional Transfers -In/+Out	(1861)	(1791)	(1752)	(1853)	(1870)	(1901)	(2044)	(2109)	(2231)
Product Inventory +Build/-Draw	(1326)	116	(121)	(27)	59	(113)	200	265	0
Add Own Consumption	2048	2241	2267	2298	2338	2383	2484	2628	2800
Total	**28031**	**29280**	**29200**	**29565**	**30295**	**30378**	**30295**	**30378**	**30295**
Per Day	76.8	80.0	80.0	81.0	83.0	83.0	83.0	83.0	83.0
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	10.5	11.7	11.9	12.4	12.6	13.8	15.3	16.0	16.8
Light	61.0	63.1	62.4	62.9	64.7	63.5	62.0	61.3	60.5
Imports	2.7	2.2	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Inventory Change	(0.1)	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	74.1	76.7	77.3	78.3	80.3	80.3	80.3	80.3	80.3
Partially Processed Oil and Other Material	2.6	3.1	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Gas Plant Butanes	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**76.8**	**80.0**	**80.0**	**81.0**	**83.0**	**83.0**	**83.0**	**83.0**	**83.0**

Note: [a] 1987 based on actual Stats. Canada Catalogue 45-004.
[b] Domestic Demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A7-16 (Continued)
Refinery Feedstock Requirements and Sources - Canada and Regions

Prairies

Low Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	16642	16977	16719	16396	16202	16060	16021	16489	17401
Deduct Product Imports	(35)	0	0	0	0	0	0	0	0
Add Product Exports	836	799	805	805	805	805	805	805	805
Net Regional Transfers -In/+Out	3087	3021	4396	4438	4341	4376	4581	4906	4623
Product Inventory +Build/-Draw	(106)	(434)	(41)	(24)	(19)	4	65	121	0
Add Own Consumption	1050	1026	1004	981	966	954	946	975	1028
Total	**21474**	**21390**	**22883**	**22595**	**22294**	**22199**	**22417**	**23296**	**23858**
Per Day	58.8	58.4	62.7	61.9	61.1	60.7	61.4	63.7	65.4
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	4.5	4.3	4.3	4.3	4.3	4.7	5.2	5.5	5.9
Light	51.0	50.8	55.3	54.6	53.7	52.9	53.2	55.1	56.4
Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inventory Change	0.1	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	55.6	55.1	59.6	58.9	58.0	57.6	58.4	60.6	62.3
Partially Processed Oil and Other Material	0.8	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Gas Plant Butanes	2.4	2.8	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Total	**58.8**	**58.4**	**62.7**	**61.9**	**61.1**	**60.7**	**61.4**	**63.7**	**65.4**

High Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	16642	17076	16900	16796	16734	16722	17000	17967	18936
Deduct Product Imports	(35)	0	0	0	0	0	0	0	0
Add Product Exports	836	828	805	805	805	805	805	805	805
Net Regional Transfers -In/+Out	3087	2909	4330	4430	4262	4283	4413	4711	4578
Product Inventory +Build/-Draw	(106)	(165)	(106)	(4)	0	54	140	143	0
Add Own Consumption	1050	1038	1025	1021	1022	1023	1047	1114	1161
Total	21474	21686	22954	23048	22823	22886	23404	24739	25480
Per Day	58.8	59.3	62.9	63.1	62.5	62.5	64.1	67.6	69.8
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	4.5	4.3	4.3	4.3	4.6	4.7	5.5	6.4	6.4
Light	51.0	52.0	55.5	55.8	54.9	54.8	55.6	58.2	60.4
Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inventory Change	0.1	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	55.6	56.2	59.8	60.1	59.5	59.5	61.1	64.5	66.8
Partially Processed Oil and Other Material	0.8	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Gas Plant Butanes	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Total	**58.8**	**59.3**	**62.9**	**63.1**	**62.5**	**62.5**	**64.1**	**67.6**	**69.8**

Note: [a] 1987 based on actual Stats. Canada Catalogue 45-004.
[b] Domestic Demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

British Columbia

Low Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	9074	9569	9490	9400	9400	9388	9430	9667	10039
Deduct Product Imports	(446)	(450)	(540)	(535)	(510)	(474)	(444)	(412)	(510)
Add Product Exports	1415	1343	1365	1365	1365	1365	1365	1365	1365
Net Regional Transfers -In/+Out	(2105)	(2162)	(3414)	(3340)	(3363)	(3380)	(3481)	(3786)	(4012)
Product Inventory +Build/-Draw	485	156	(11)	5	3	17	43	67	0
Add Own Consumption	405	487	483	478	479	478	480	492	511
Total	**8828**	**8943**	**7373**	**7373**	**7373**	**7393**	**7393**	**7393**	**7393**
Per Day	24.2	24.4	20.2	20.2	20.2	20.2	20.3	20.2	20.3
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light	21.0	20.0	15.8	15.8	15.8	15.8	15.9	15.8	16.1
Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inventory Change	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	21.2	20.0	15.8	15.8	15.8	15.8	15.9	15.8	16.1
Partially Processed Oil and Other Material	2.9	4.4	4.3	4.3	4.3	4.3	4.3	4.3	4.1
Gas Plant Butanes	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**24.2**	**24.4**	**20.2**	**20.2**	**20.2**	**20.2**	**20.3**	**20.2**	**20.3**

High Case

Feedstock Requirements (Thousands of Cubic Metres)	1987 [a]	1988	1989	1990	1991	1992	1995	2000	2005
Domestic Product Demand [b]	9074	9439	9325	9244	9204	9195	9150	9417	9984
Deduct Product Imports	(446)	(380)	(440)	(374)	(384)	(355)	(339)	(373)	(519)
Add Product Exports	1415	1343	1365	1365	1365	1365	1365	1365	1365
Net Regional Transfers -In/+Out	(2105)	(2050)	(3348)	(3332)	(3284)	(3287)	(3313)	(3591)	(3967)
Product Inventory +Build/-Draw	485	135	(3)	0	4	7	44	96	0
Add Own Consumption	405	480	474	470	468	468	465	480	509
Total	**8828**	**8967**	**7373**	**7373**	**7373**	**7393**	**7373**	**7393**	**7373**
Per Day	24.2	24.5	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Feedstock Sources (Thousands of Cubic Metres per Day)									
Domestic: Heavy	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light	21.0	20.0	15.8	15.8	15.8	15.8	15.8	15.8	15.8
Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inventory Change	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	21.2	20.0	15.8	15.8	15.8	15.8	15.8	15.8	15.8
Partially Processed Oil and Other Material	2.9	4.4	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Gas Plant Butanes	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**24.2**	**24.5**	**20.2**	**20.2**	**20.2**	**20.2**	**20.2**	**20.2**	**20.2**

Note: [a] 1987 based on actual Stats. Canada Catalogue 45-004.
[b] Domestic demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A7-17
Supply and Disposition of Domestic Crude Oil and Equivalent - Canada

(Thousands of Cubic Metres per Day)

Low Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Heavy Crude Oil										
Domestic Supply										
Actual Production and Productive Capacity	64.2	74.2	76.4	74.6	79.0	76.5	69.1	59.4	55.4	61.0
Inventory -Build/+Draft	3.6	(0.4)								
Total Domestic Supply	**67.8**	**73.8**	**76.4**	**74.6**	**79.0**	**76.5**	**69.1**	**59.4**	**55.4**	**61.0**
Disposition of Domestic Supply										
Feedstocks										
Atlantic	0.3	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0
Quebec	2.4	2.8	1.4	1.5	1.5	1.5	1.6	1.7	0.0	0.0
Ontario	8.3	10.5	11.7	11.9	12.2	12.2	13.7	15.1	15.7	16.2
Eastern Canada	11.0	13.6	13.5	13.8	13.7	13.7	15.3	16.8	15.7	16.2
Prairies & NWT	4.5	4.5	4.3	4.3	4.3	4.3	4.7	5.2	5.5	5.9
British Columbia & Yukon	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Western Canada	4.5	4.7	4.3	4.3	4.3	4.3	4.7	5.2	5.5	5.9
Canada	15.5	18.4	17.8	18.1	18.0	18.0	20.0	22.0	21.2	22.1
Exports	**52.3**	**55.4**	**58.6**	**56.5**	**61.0**	**58.5**	**49.1**	**37.4**	**34.2**	**38.9**
Light Crude Oil and Equivalent										
Domestic Supply										
Actual Production and Productive Capacity										
East Coast									10.0	13.0
Beaufort Sea										
W. Canada	185.8	194.6	195.5	193.5	184.2	177.9	176.0	161.3	137.7	120.5
Inventory -Build/+Draft	0.1	(6.9)								
Total Domestic Supply	**185.9**	**187.7**	**195.5**	**193.5**	**184.2**	**177.9**	**176.0**	**161.3**	**147.7**	**133.5**
Disposition of Domestic Supply										
Feedstocks										
Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	13.0
Quebec	13.2	10.5	15.6	15.0	15.0	15.0	15.0	15.0	0.0	0.0
Ontario	62.5	61.0	63.1	63.2	63.9	65.9	64.4	63.0	59.8	41.0
Eastern Canada	75.7	71.5	78.7	78.2	78.9	80.9	79.4	78.0	69.8	54.0
Prairies & NWT	48.1	51.0	50.8	55.3	54.6	53.7	52.9	53.2	55.1	56.4
British Columbia & Yukon	20.8	21.0	20.0	15.8	15.8	15.8	15.8	15.9	15.8	16.1
Western Canada	68.9	71.9	70.8	71.1	70.3	69.5	68.7	69.0	70.9	72.5
Canada	144.6	143.5	149.5	149.3	149.2	150.4	148.1	147.0	140.7	126.5
Min. Exports via Rangeland			7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Total Exports	**41.3**	**44.2**	**46.0**	**44.2**	**35.0**	**27.5**	**27.9**	**14.3**	**7.0**	**7.0**

Table A7-17 (Continued)
Supply and Disposition of Domestic Crude Oil and Equivalent - Canada

(Thousands of Cubic Metres per Day)

High Case

	1986	1987	1988	1989	1990	1991	1992	1995	2000	2005
Heavy Crude Oil										
Domestic Supply										
Actual Production and Productive Capacity	64.2	74.2	79.7	83.3	97.7	102.2	98.3	127.6	122.4	123.7
Inventory -Build/+Draft	3.6	(0.4)								
Total Domestic Supply	**67.8**	**73.8**	**79.7**	**83.3**	**97.7**	**102.2**	**98.3**	**127.6**	**122.4**	**123.7**
Disposition of Domestic Supply										
Feedstocks										
Atlantic	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5
Quebec	2.4	2.8	1.4	1.5	1.5	1.5	1.6	1.7	1.8	2.0
Ontario	8.3	10.5	11.7	11.9	12.4	12.6	13.8	15.3	16.0	16.8
Eastern Canada	11.0	13.6	13.5	13.8	14.3	14.5	15.8	17.5	18.3	19.3
Prairies & NWT	4.5	4.5	4.3	4.3	4.3	4.6	4.7	5.5	6.4	6.4
British Columbia & Yukon	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Western Canada	4.5	4.7	4.3	4.3	4.3	4.6	4.7	5.5	6.4	6.4
Canada	15.5	18.4	17.8	18.1	18.6	19.1	20.5	23.0	24.7	25.7
Exports	**52.3**	**55.4**	**61.9**	**65.2**	**79.1**	**83.1**	**77.8**	**104.6**	**97.7**	**98.0**
Light Crude Oil and Equivalent										
Domestic Supply										
Actual Product and Productive Capacity										
East Coast							1.5	13.4	25.0	25.0
Beaufort Sea					1.9	1.9	1.9	2.0	24.0	24.0
W. Canada	185.8	194.6	198.9	199.0	189.8	184.4	184.0	161.0	153.4	149.2
Inventory -Build/+Draft	0.1	(6.9)								
Total Domestic Supply	**185.9**	**187.7**	**198.9**	**199.0**	**191.7**	**186.3**	**187.4**	**176.4**	**202.4**	**198.2**
Disposition of Domestic Supply										
Feedstocks										
Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	1.5	13.4	25.0	25.0
Quebec	13.2	10.5	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Ontario	62.5	61.0	63.1	62.4	62.9	64.7	63.5	62.0	61.3	60.5
Eastern Canada	75.7	71.5	78.7	77.4	77.9	79.7	79.9	90.4	101.2	100.5
Prairies & NWT	48.1	51.0	52.0	55.5	55.8	54.9	54.8	55.6	58.2	60.4
British Columbia & Yukon	20.8	21.0	20.0	15.8	15.8	15.8	15.8	15.8	15.8	15.8
Western Canada	68.9	71.9	72.0	71.3	71.6	70.7	70.6	71.4	74.0	76.2
Canada	144.6	143.5	150.7	148.7	149.5	150.3	150.5	161.7	175.2	176.6
Min. Exports via Rangeland			7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Total Exports	**41.3**	**44.2**	**48.2**	**50.3**	**42.2**	**36.0**	**36.9**	**14.7**	**27.2**	**21.6**

Table A7-18
Major Energy Projects Included In Our Projections

Project	Peak Production Rate	Year of First Production Low Case	Year of First Production High Case
Oil	(Thousands of Cubic Metres per Day)		
Bi - Provincial Upgrader	7	1992	1992
Hibernia	18		1995
Mining Project 1	12		1996
Amauligak	24		1997
Upgrader	10		1998
Mining Project 2	12		2000
Mining Project 3	12		2004
Gas	(Millions of Cubic Metres per Day)		
Mackenzie Delta	32	1999	1999
Venture Multi - Field	18		2004

Appendix 8

Table A8-1

Historical Data - Natural Gas Liquids Production - Canada

(Thousands of Cubic Metres per Day)

	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
Ethane										
Gas Plants[a]	-	0.1	0.3	0.4	1.0	0.9	1.1	1.7	1.7	1.5
Propane										
Gas Plants[a]	6.4	7.1	8.2	9.8	12.2	14.5	16.4	16.3	17.0	16.2
Refineries[b]	2.0	2.0	2.1	2.3	2.3	2.3	2.6	2.6	3.1	3.5
Total	8.4	9.1	10.3	12.1	14.5	16.8	19.0	18.9	20.1	19.7
Butanes										
Gas Plants[a]	4.2	4.8	5.2	6.4	8.0	9.6	10.8	11.0	11.2	10.8
Refineries[b]	1.7	1.6	1.5	1.2	0.7	0.4	0.7	0.9	1.0	1.0
Total	5.9	6.4	6.7	7.6	8.7	10.0	11.5	11.9	12.2	11.8
Pentanes Plus										
Gas Plants[a,c]	13.3	14.4	16.9	19.4	21.0	26.8	27.6	26.4	24.8	21.8

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Ethane										
Gas Plants[a]	1.8	4.8	10.8	13.1	13.8	12.7	13.9	16.6	18.1	20.9
Propane										
Gas Plants[a]	16.3	15.5	16.9	16.2	15.8	15.8	15.3	16.5	16.9	17.3
Refineries[b]	3.7	3.6	3.5	3.8	3.7	3.2	3.5	3.6	3.1	3.6
Total	20.0	19.1	20.4	20.0	19.5	19.0	18.8	20.1	20.0	20.9
Butanes										
Gas Plants[a]	10.9	10.1	10.9	10.2	9.8	9.8	9.5	9.8	9.7	9.6
Refineries[b]	1.4	1.5	1.9	2.3	2.9	2.5	2.6	2.4	2.2	2.3
Total	12.3	11.6	12.8	12.5	12.7	12.3	12.1	12.2	11.9	11.9
Pentanes Plus										
Gas Plants[a,c]	21.5	19.4	19.3	17.4	16.7	16.4	15.4	16.1	17.2	17.4

Notes:[a] Provincial NGL gas plant production figures have been adjusted upwards to account for each gas liquid component of mixes injected in miscible flood or other injection schemes. Production of specification ethane did not begin until 1974.

[b] Refinery production is net of own use. Source: 1967 - 1974 Statistics Canada, and 1975 - 1986 NEB 145 summaries.

[c] Includes field condensate production.

Table A8-2
Natural Gas Liquids Production - Canada

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Ethane									
Gas Plants	25.5	28.1	28.9	29.5	29.3	29.4	28.4	27.3	26.6
Propane									
Gas Plants	19.1	20.6	20.8	20.5	20.4	20.6	20.5	19.8	20.1
Refineries	3.9	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.3
Total	23.0	24.7	25.0	24.7	24.6	24.8	24.7	24.0	24.4
Butanes									
Gas Plants	10.5	11.1	11.5	11.3	11.2	11.3	11.2	10.6	10.7
Refineries	3.5	3.7	3.7	3.7	3.8	3.8	3.8	3.8	3.8
Total	14.0	14.8	15.2	15.0	15.0	15.1	15.0	14.4	14.5
Pentanes Plus[a]									
Gas Plants	18.6	19.2	18.7	18.0	18.1	17.7	17.1	18.5	19.7

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Ethane									
Gas Plants	25.5	28.2	29.2	30.0	30.0	30.2	29.3	27.3	26.6
Propane									
Gas Plants	19.1	20.7	21.2	21.1	21.3	21.5	21.9	21.3	21.3
Refineries	3.9	4.2	4.2	4.2	4.2	4.2	4.2	4.3	4.3
Total	23.0	24.9	25.4	25.3	25.5	25.7	26.1	25.6	25.6
Butanes									
Gas Plants	10.5	11.2	11.7	11.7	11.7	11.8	12.0	11.6	11.5
Refineries	3.5	3.7	3.7	3.8	3.8	3.8	3.8	3.9	3.9
Total	14.0	14.9	15.4	15.5	15.5	15.6	15.8	15.5	15.4
Pentanes Plus[a]									
Gas Plants	18.6	19.3	19.1	18.6	18.9	18.6	18.2	20.0	22.5

Note:[a] Includes field condensate.

Table A8-3
Ethane Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Alberta									
Bonnie Glen (Texaco)	749	725	1299	1761	1553	1447	1074	788	590
Brazeau River (Chevron)*	50	125	118	93	74	59	30	10	3
Elmworth (Cdn Hunter)*	598	750	800	800	800	760	600	300	150
Elmworth (Esso)*	730	900	900	900	865	830	500	200	100
Judy Creek (Esso)*	2402	2366	2317	2216	2116	2069	1750	1389	1579
Jumping Pound (Shell)	411	400	389	379	366	349	289	260	150
Kaybob South (Chevron)*	723	750	750	725	700	650	500	200	100
Peco (Ocelot)*	120	130	125	120	115	110	100	70	60
Rainbow (Total)*	862	839	810	735	637	550	342	150	200
Turner Valley (W. Decalta)	154	160	160	160	160	160	160	100	60
Waterton (Shell)	709	676	633	598	572	551	377	166	83
Wembley (Dome)*	363	400	400	400	400	400	400	350	300
Other*	101	112	110	109	103	88	54	26	13
Subtotal	7972	8333	8811	8996	8461	8023	6176	4009	3388
Cochrane	6280	6562	6265	6296	6296	6421	6421	6421	6421
Ellerslie	1828	1850	1853	1877	1881	1884	1884	1900	1925
Empress	9202	11094	11727	12026	12409	12861	13641	14700	14700
Fort Saskatchewan (Norcen)	108	108	108	108	108	108	108	108	108
Alberta-Total	25390	27947	28764	29303	29155	29297	28230	27138	26542
Saskatchewan-Total	150	155	155	152	150	147	135	120	90
Canada-Total	25540	28102	28919	29455	29305	29444	28365	27258	26632

Note:[*] All or part of the production is entrained in an ethane plus mix.

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Alberta									
Field Plant									
Subtotal[a]	7972	8333	8811	8996	8461	8023	6176	4009	3388
Cochrane	6280	6562	6265	6296	6296	6421	6421	6421	6421
Ellerslie	1828	1850	1853	1877	1881	1884	1884	1900	1925
Empress	9202	11178	12027	12597	13077	13634	14621	14700	14700
Fort Saskatchewan (Norcen)	108	108	108	108	108	108	108	108	108
Alberta-Total	25390	28031	29064	29874	29823	30070	29210	27138	26542
Saskatchewan-Total	150	155	155	152	150	147	135	120	90
Canada-Total	25540	28186	29219	30026	29973	30217	29345	27258	26632

Note:[a] See Low Case for details.

Table A8-4
Propane Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
British Columbia-Total	632	682	700	698	710	723	739	722	701
Alberta									
From Existing Plants									
Acheson (ICG)	92	81	72	64	56	50	35	19	10
Ante Creek (Amoco)*	24	24	24	23	22	20	16	10	10
Bonnie Glen (Texaco)	1021	910	874	742	646	564	403	288	206
Brazeau (Chevron)*	76	90	80	64	51	40	20	7	2
Brazeau (Petro-Canada,2 Plants)*	154	143	116	94	78	66	43	20	99
Brazeau (Wolcott)*	87	74	61	50	42	34	20	8	2
Campbell Namao (Norcen)	21	19	17	15	14	12	9	4	2
Caroline (All Plants)	148	141	133	127	120	114	98	76	59
Carrot Creek (All Plants)*	41	35	30	26	23	20	12	8	5
Carson Creek (Mobil)	245	241	215	193	175	161	106	38	10
Carstairs (Home)	209	194	172	149	131	115	72	53	39
Cranberry (All Plants)*	104	107	104	101	98	95	83	66	53
Crossfield (Petrogas)	118	108	98	90	82	75	57	36	23
Elmworth (Cdn Hunter)*	252	248	224	200	178	159	113	64	37
Elmworth (Esso)*	239	214	192	171	153	137	98	56	32
Ferrier (Amerada)	183	170	158	147	136	127	102	70	49
Ferrier (Others)*	40	36	32	28	25	23	17	11	6
Garrington (All Plants)*	118	105	96	85	76	68	50	30	21
Ghost Pine (Gulf)*	42	41	40	38	37	37	29	19	13
Gilby (All Plants)*	100	106	110	110	104	98	77	56	42
Harmattan Elkton (Cdn Sup)	403	381	362	341	323	305	259	196	148
Homeglen-Rimbey (Gulf)	905	857	811	768	727	689	585	445	339
Hussar (All Plants)*	66	65	63	62	60	58	50	39	31
Joffre (All Plants)*	20	19	17	15	13	11	8	5	3
Judy Creek (Esso)*	1546	1553	1498	1433	1368	1304	1128	893	1112
Jumping Pound (Shell)	167	162	157	153	148	141	117	86	62
Karr (Canadian Hunter)*	124	163	163	163	162	162	152	102	68
Kaybob (Petro-Canada)*	102	96	91	81	72	64	45	27	15
Kaybob South (Chevron)*	374	338	301	267	317	255	146	62	48
Kaybob South (Dome)*	391	375	335	290	298	253	163	73	41
Leduc-Woodbend (Esso)	130	125	120	117	115	110	110	110	110
Minnehik-Buck L. (Norcen)*	39	35	32	29	26	24	18	11	7
Mitsue (Chevron)	0	0	342	342	330	302	229	143	88
Nevis (Gulf)	262	210	168	134	108	86	44	14	5
Nipisi (Amoco)*	158	158	158	158	150	126	73	30	12
Niton (Esso)*	28	37	37	37	37	37	37	27	17
Paddle R (Canadian Oxy.)*	95	90	84	79	75	70	58	43	32
Peco (Ocelot)*	56	52	49	46	42	40	34	27	22
Pembina (All Plants)	377	358	340	323	307	292	250	194	150
Quirk Creek (Esso)	48	80	111	106	102	99	89	63	44
Rainbow (All Plants)*	983	940	850	764	685	613	437	244	128
Redwater (Esso)	50	44	36	33	29	25	17	11	8
Ricinus (Amoco)	349	321	296	272	250	230	180	119	78
Simonette (Shell)*	29	25	22	19	17	15	11	7	4
Strachan (Gulf)	171	167	164	160	157	154	145	131	118
Sturgeon Lake South (Dome)*	21	19	16	14	12	10	6	3	1
Swan Hills (Shell)*	44	43	40	36	34	31	25	18	14
Sylvan Lake (Chevron)	58	52	46	40	35	31	22	14	8
Sylvan Lake (HBOG)	92	87	83	78	71	65	54	34	22
Sylvan Lake (General American)	25	29	34	32	31	29	18	9	4
Turner Valley (W. Decalta)	105	88	74	38	32	27	16	0	0
Twining (Mobil)*	26	34	42	40	37	33	25	16	10
Waterton (Shell)	345	324	302	248	241	235	163	72	37
Wayne Rosedale (All Plants)	39	37	35	34	31	29	25	19	14

(Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Wembley (Dome)*	232	231	221	212	202	192	156	118	114
Willesden Green (Dome)	48	44	41	38	35	33	26	18	12
Willesden Green (Texaco)*	34	31	28	24	22	20	15	10	7
Other Field Plants	830	850	820	790	760	725	600	475	375
Subtotal	12086	11607	11237	10333	9708	8940	6996	4847	4028
Cochrane	1625	1698	1621	1629	1629	1661	1661	1661	1661
Ellerslie	834	850	872	876	880	873	870	809	742
Empress	3550	4280	4524	4640	4787	4962	5262	5676	5985
Fort Saskatchewan (Norcen)	64	64	64	64	64	64	64	64	64
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	1105	1560	1954	2395	3098	4696	5862	6739
Alberta-Total	18159	19604	19878	19496	19463	19598	19549	18919	19219
Saskatchewan-Total	255	260	260	255	250	245	225	200	150
Manitoba-Total	10	10	10	10	9	9	8	7	6
Canada-Total	19056	20556	20848	20459	20432	20575	20521	19848	20076

Note:[*] All or part of the production is entrained in an NGL mix.

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
British Columbia-Total	632	685	704	709	724	737	745	722	701
Alberta									
Existing Plants[a]	12086	11607	11237	10333	9708	8940	6996	4847	4028
Cochrane	1625	1698	1621	1629	1629	1661	1661	1661	1661
Ellerslie	834	850	872	876	880	873	870	809	742
Empress	3550	4312	4640	4860	5045	5260	5641	6134	6200
Fort Saskatchewan (Norcen)	64	64	64	64	64	64	64	64	64
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	1180	1760	2378	2962	3696	5651	6855	6965
Alberta-Total	18159	19711	20194	20140	20288	20494	20883	20370	19660
Saskatchewan-Total	255	260	260	255	250	245	225	200	150
Manitoba-Total	10	10	10	10	9	9	8	7	6
Frontier-Total	0	0	0	0	0	0	0	0	750
Canada-Total	19056	20666	21168	21114	21271	21485	21861	21299	21267

Note: [a]See Low Case for detailed projections.

Table A8-5
Butanes Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
British Columbia-Total	388	431	435	430	431	433	429	409	387
Alberta									
From Existing Plants									
Acheson (ICG)	44	37	32	27	23	19	11	5	2
Ante Creek (Amoco)*	14	14	13	13	12	12	9	6	7
Bonnie Glen (Texaco)	626	574	487	420	359	313	224	160	115
Brazeau (Chevron)*	44	51	46	37	29	23	11	4	1
Brazeau (Petro-Canada,2 Plants)*	93	79	63	52	44	38	24	11	44
Brazeau (Wolcott)*	87	75	63	53	45	38	23	11	4
Campbell Namao (Norcen)	14	13	11	10	9	8	6	3	1
Caroline (All Plants)	153	145	138	131	125	118	102	79	61
Carrot Creek (All Plants)*	29	25	22	19	17	15	10	6	4
Carson Creek (Mobil)	139	119	105	81	72	64	41	14	3
Carstairs (Home)	145	137	121	112	98	86	52	38	28
Cranberry (All Plants)*	63	66	64	63	61	59	52	42	34
Crossfield (Petrogas)	83	76	70	64	59	54	41	27	17
Elmworth (Cdn Hunter)*	101	100	91	81	72	64	46	26	15
Elmworth (Esso)*	128	115	103	92	82	74	53	30	18
Ferrier (Amerada)	87	81	76	71	66	62	53	39	28
Ferrier (Others)*	55	53	45	38	33	29	20	11	5
Garrington (All Plants)*	72	64	58	51	46	41	30	19	13
Ghost Pine (Gulf)*	47	46	45	44	43	42	34	22	15
Gilby (All Plants)*	71	74	80	76	71	68	54	39	31
Harmattan Elkton (Cdn Sup)	273	251	231	212	195	179	140	92	60
Homeglen-Rimbey (Gulf)	524	493	463	435	409	385	319	234	172
Hussar (All Plants)	62	60	59	58	57	54	47	37	30
Joffre (All Plants)*	17	16	15	12	11	10	7	6	3
Judy Creek (Esso)*	871	882	853	815	777	739	635	499	555
Jumping Pound (Shell)	146	142	138	134	129	123	102	75	54
Karr (Canadian Hunter)*	50	66	65	65	65	65	61	41	27
Kaybob (Petro-Canada)*	66	63	59	54	48	43	32	20	12
Kaybob South (Chevron)*	257	223	192	163	215	160	66	2	0
Kaybob South (Dome)*	289	272	244	215	232	186	105	34	19
Leduc-Woodbend (Esso)	125	215	205	197	190	184	167	47	21
Minnehik-Buck L. (Norcen)*	31	28	26	23	21	19	14	9	5
Mitsue (Chevron)	0	0	211	211	211	194	147	92	57
Nevis (Gulf)	176	141	113	90	72	58	30	10	3
Nipisi (Amoco)*	143	143	143	143	136	114	66	27	11
Niton (Esso)	27	36	36	36	36	36	35	26	16
Paddle R (Canadian Oxy.)*	53	49	46	44	41	39	32	24	17
Peco (Ocelot)*	23	22	21	19	18	17	15	12	10
Pembina (All Plants)	253	240	228	217	206	196	168	130	100
Quirk Creek (Esso)	37	63	90	87	83	81	73	52	36
Rainbow (All Plants)*	783	749	699	644	587	533	393	253	220
Redwater (Esso)	36	32	28	25	22	19	14	9	6
Ricinus (Amoco)	192	179	185	167	151	137	99	87	56
Simonette (Shell)*	18	16	14	12	11	9	7	4	2
Strachan (Gulf)	137	102	87	74	63	54	36	6	4
Sturgeon Lake South (Dome)*	9	8	7	6	5	4	2	1	0
Swan Hills (Shell)*	4	4	4	4	3	3	3	2	1
Sylvan Lake (Chevron)	45	41	37	33	29	27	20	13	8
Sylvan Lake (HBOG)	54	55	51	46	43	39	33	20	13
Sylvan Lake (General American)	26	30	33	31	29	27	17	8	4
Turner Valley (W Decalta)	63	53	44	37	31	26	15	0	0
Twining (Mobil)*	10	13	16	16	14	13	10	6	4
Waterton (Shell)	284	268	250	236	229	223	155	70	36
Wayne Rosedale (All Plants)	36	35	32	30	28	27	23	17	13

(Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Wembley (Dome)*	153	153	147	141	135	129	106	82	80
Willesden Green (Dome)	47	43	40	37	34	32	25	17	11
Willesden Green (Texaco)*	21	19	17	15	13	12	9	6	4
Other Field Plants	259	288	276	255	240	219	166	107	85
Subtotal	7695	7437	7138	6574	6185	5642	4290	2769	2201
Cochrane	503	525	501	504	504	514	514	514	514
Ellerslie	321	327	328	328	328	332	335	344	315
Empress	1377	1661	1755	1800	1858	1925	2042	2202	2322
Fort Saskatchewan (Norcen)	32	32	32	32	32	32	32	32	32
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	480	1114	1396	1711	2213	3354	4187	4813
Alberta-Total	9928	10462	10868	10634	10618	10658	10567	10048	10197
Saskatchewan-Total	199	200	200	195	190	188	175	155	115
Manitoba-Total	3	3	3	3	3	3	3	2	1
Canada-Total	10518	11096	11506	11262	11242	11282	11174	10614	10700

Note:[*] All or part of the production is entrained in an NGL mix.

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
British Columbia-Total	388	432	436	434	436	438	431	409	387
Alberta									
Existing Field Plants[a]	7695	7437	7138	6574	6185	5642	4290	2769	2201
Cochrane	503	525	501	504	504	514	514	514	514
Ellerslie	321	327	328	328	328	332	335	344	315
Empress	1377	1673	1800	1886	1958	2041	2189	2380	2400
Fort Saskatchewan (Norcen)	32	32	32	32	32	32	32	32	32
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	540	1257	1699	2090	2640	4036	4997	4975
Alberta-Total	9928	10534	11056	11023	11097	11201	11396	11036	10437
Saskatchewan-Total	199	200	200	195	190	188	175	155	115
Manitoba-Total	3	3	3	3	3	3	3	2	1
Frontier-Total	0	0	0	0	0	0	0	0	600
Canada-Total	10518	11169	11695	11655	11726	11830	12005	11602	11540

Note: [a]See Low Case for detailed plant projections.

Table A8-6
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
British Columbia[a]									
Total	585	630	617	601	576	575	544	493	446
Alberta									
Bow River Pipelines									
Empress (Petro-Canada)	242	291	308	316	326	338	358	387	407
Provost*	52	47	45	43	40	38	33	25	20
Vulcan	28	25	24	21	20	18	14	6	4
Others	97	96	91	87	82	78	67	52	40
Total	419	459	468	467	468	472	472	470	471
Co-ed Pipe Line									
Caroline (Dome)	169	153	136	122	109	98	71	45	33
Cochrane	198	206	197	198	198	202	202	202	202
Ellerslie (Dome)	146	147	148	148	149	150	145	150	138
Empress (Dome)	267	321	340	349	360	373	395	427	450
Empress (Wolcott)	40	48	51	52	54	56	59	64	67
Ferrier (4 Plants)*	71	62	50	42	34	28	16	7	0
Garrington (4 Plants)	25	16	13	10	8	7	3	1	0
Judy Creek (Esso)*	608	617	599	573	547	521	449	353	400
Leduc-Woodbend	74	71	68	66	65	62	62	62	62
Minnehik-Buck Lake (Norcen)*	250	227	205	186	169	155	116	71	43
Pembina*	191	181	172	163	155	147	127	98	76
Quirk Creek*	61	74	82	79	76	74	69	50	34
Ricinus (Amoco)	245	193	153	124	109	96	116	93	60
Ricinus West (Canterra)	129	124	114	106	101	96	76	18	9
Strachan (Gulf)	424	349	290	245	207	177	118	12	9
Willesden Green (Dome)	33	29	27	26	24	23	19	14	10
Others	26	22	18	14	10	6	4	2	0
Total	2957	2840	2663	2503	2375	2271	2047	1669	1593
Cremona Pipeline									
Burnt Timber (Shell)	20	21	20	19	18	18	16	12	9
Carstairs (Home)	250	220	192	166	143	124	72	53	39
Crossfield (Petrogas)	149	135	123	111	102	93	71	45	29
Crossfield East (Amoco)	17	15	11	9	7	5	4	3	3
Garrington (Amerada)	66	66	67	65	59	56	47	35	27
Harmattan Elkton (Cdn Superior)	541	477	420	334	346	316	257	127	58
Lone Pine Creek (Cdn Sup)	17	15	13	11	10	9	6	3	2
Lone Pine Creek (HBOG)	93	78	65	55	47	37	19	12	7
Other	94	89	85	80	77	72	62	48	37
Total	1247	1116	996	850	809	730	554	338	211
Federated Pipe Lines									
Total	102	97	91	86	80	75	69	58	46

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
				Gibson Petroleum					
Acheson (ICG)	22	22	18	13	10	8	4	2	1
Paddle River*	46	43	40	38	36	34	28	21	16
Wilson Creek (Amerada)	27	26	25	23	21	20	16	11	8
Total	95	91	83	74	67	62	48	34	25
				Gulf Alberta Pipe Line					
Cessford (HBOG)	9	9	9	9	9	9	8	8	6
Ghost Pine (Gulf)*	60	60	58	66	65	63	51	33	20
Hussar (Canterra)	29	29	29	28	28	27	23	18	15
Nevis (Gulf)	131	110	91	77	67	60	42	25	16
Wayne Rosedale (All Plants)	24	24	22	21	19	18	15	10	7
Others	181	172	163	155	147	140	120	93	72
Total	434	404	372	356	335	317	259	187	136
				Imperial Pipe Line - Excelsior					
Total	2	2	2	2	2	1	1	1	1
				Imperial Pipe Line - Ellerslie					
Campbell Namao (Norcen)	13	12	10	9	8	7	5	3	1
Total	13	12	10	9	8	7	5	3	1
				Imperial Pipe Line - Redwater					
Redwater	18	16	13	11	10	8	5	2	1
Total	18	16	13	11	10	8	5	2	1
				Murphy Oil					
Total	2	2	2	1	1	1	1	1	1
				Peace River Oil Pipe Line					
Carson Creek (Mobil)	164	152	140	105	98	92	63	23	7
Dunvegan (Anderson)*	116	110	105	99	93	89	71	55	41
Elmworth (Total)*	271	250	224	200	179	160	114	65	37
Gold Creek	84	81	76	72	68	65	53	38	25
Greencourt	8	8	8	8	7	6	3	1	1
Josephine	18	19	19	19	18	18	15	10	8
Karr(Cdn Hunter)*	42	52	52	51	51	50	46	31	21
Kaybob (Petro-Canada)*	108	104	100	93	86	80	66	48	34
Kaybob South (Chevron)*	1079	1003	931	864	952	713	306	24	19
Kaybob South (HBOG)*	1086	1046	964	875	885	708	384	118	64
Simonette (Shell)*	44	37	32	27	23	20	13	6	2
Sinclair (Dome)	48	39	32	26	21	17	9	3	1
Sturgeon Lake South*	51	45	39	33	28	23	14	6	3
Wapiti (Amoco)	113	105	98	91	85	79	63	44	31
Wembley	449	468	466	464	460	454	412	370	363
Whitecourt	19	19	18	17	17	16	14	12	10
Windfall	330	252	201	150	113	87	42	16	5
Others	261	252	242	233	223	215	191	157	125
Total	4291	4042	3747	3427	3407	2892	1879	1027	797

Table A8-6 (continued)
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Pembina Pipe Line									
Brazeau (Canterra)	29	32	30	29	28	27	23	18	14
Brazeau (HBOG)	122	118	115	114	112	104	79	50	32
Brazeau (Petro-Canada,2 Plants)*	647	535	439	365	312	253	146	56	17
Brazeau (Wolcott)*	930	784	647	534	442	367	215	85	24
Carrot Creek (Amoco & Coop)*	34	29	26	23	20	19	11	8	6
Leaman (Dome)*	27	24	22	20	18	17	12	8	5
Niton (Esso)*	22	30	30	30	30	30	30	22	14
Peco (Ocelot)*	73	69	64	61	55	52	46	37	30
Pembina*	382	363	344	328	312	295	254	196	151
Rosevear (Shell)	19	18	17	17	16	15	13	11	8
Rosevear (Suncor)	11	10	10	10	9	8	7	6	5
Willesden Green (2 Plants)	30	29	27	24	20	18	12	6	4
Others	169	161	153	145	138	131	112	86	68
Total	2495	2202	1924	1700	1512	1336	960	589	378
Rainbow Pipe Line									
Cranberry (Dome)*	305	293	274	256	239	224	180	129	95
Cranberry (Shell)*	60	57	56	54	53	50	45	38	33
Mitsue (Chevron)	0	0	136	132	121	111	84	53	32
Nipisi (Amoco)*	96	97	97	97	92	77	45	18	7
Rainbow (Total)*	565	543	520	500	480	461	408	333	271
Others	55	52	50	47	45	43	36	28	22
Total	1081	1042	1133	1086	1030	966	798	599	460
Rangeland Pipe Line									
Caroline (HBOG)	80	80	76	71	67	64	54	40	30
Ferrier (Amerada)	63	58	53	48	45	41	33	23	6
Gilby (Chevron)*	14	13	11	10	9	8	5	3	2
Gilby (Petro-Canada)*	29	28	27	26	25	22	17	12	9
Gilby (Others)	26	25	24	21	20	19	15	11	7
Sylvan Lake (Chevron)	33	29	26	23	20	17	13	8	4
Sylvan Lake(Phillips)	39	42	46	43	40	37	24	11	5
Sylvan Lake (HBOG)	44	43	40	37	34	31	25	15	9
Twining (Mobil)	15	19	23	22	20	19	14	9	6
Waterton (Shell)	866	804	750	665	629	595	390	181	110
Wimborne (Mobil)	42	39	36	34	32	30	24	17	12
Others	101	96	91	87	82	78	67	52	40
Total	1352	1276	1203	1087	1023	961	681	382	240
Rimbey Pipe Line									
Bonnie Glen (Texaco)	684	603	506	456	399	365	263	190	137
Homeglen-Rimbey (Gulf)	683	654	573	505	450	403	291	175	114
Total	1367	1257	1079	961	849	768	554	365	251
Texaco Canada Resources									
Total	2	2	2	2	1	1	1	1	1

Table A8-6 (continued)
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
			Valley Pipe Line						
Gilby (Texaco)*	36	34	32	31	29	28	23	19	15
Jumping Pound (Shell)	393	377	361	346	329	309	249	176	125
Diamond Valley (West. Decalta)	57	48	40	34	28	24	14	0	0
Wildcat Hills (Petro-Canada)	67	65	63	63	61	59	54	47	40
Others	17	16	15	15	14	13	11	9	7
Total	570	540	511	489	461	433	351	251	187
			Truck and Tank Car						
Edson (HBOG)	167	153	137	128	113	101	73	44	28
Sundance (Dome)	45	39	31	25	20	16	8	3	0
Others	1001	1002	950	900	858	815	697	541	419
Total	1213	1194	1118	1053	991	932	778	588	447
			Field Condensate						
Total	266	251	236	222	209	197	165	122	90
Subtotal	17926	16845	15653	14386	13638	12430	9628	6687	5337
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	1610	2273	2847	3740	4574	6842	8542	9819
Alberta-Total	17926	18455	17926	17233	17378	17004	16470	15229	15156
			Saskatchewan[a]						
Total	115	115	115	114	112	110	101	90	68
			Manitoba						
Total	2	2	2	2	2	2	2	1	1
			Frontier						
Total	0	0	0	0	0	0	0	2700	4000
			Canada						
Canada-Total	18628	19202	18660	17950	18068	17691	17117	18513	19671

Table A8-6 (continued)
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Thousands of Cubic Metres per Day)

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
British Columbia-Total[a]	585	631	618	603	581	579	549	498	451
Alberta									
Bow River Pipelines	419	462	476	482	486	492	498	501	487
Co-ed Pipe Line	2957	2844	2673	2522	2397	2296	2081	1708	1613
Cremona Pipeline	1247	1116	996	850	809	730	554	338	211
Federated Pipe Lines	102	97	91	86	80	75	69	58	46
Gibson Petroleum	95	91	83	74	67	62	48	34	25
Gulf Alberta Pipe Line	434	404	372	356	335	317	259	187	136
Imperial Pipeline Excelsior	2	2	2	2	2	1	1	1	1
Imperial Pipeline Ellerslie	13	12	120	9	8	7	5	3	1
Imperial Pipeline Redwater	18	16	13	11	10	8	5	2	1
Murphy Oil	2	2	2	1	1	1	1	1	1
Peace River Oil Pipe Line	4291	4042	3747	3427	3407	2892	1879	1027	797
Pembina Pipe Line	2495	2202	1924	1700	1512	1336	960	589	378
Rainbow Pipe Line	1081	1042	1133	1086	1030	966	798	599	460
Rangeland Pipe line	1352	1276	1203	1087	1023	961	681	382	240
Rimbey Pipe Line	1367	1257	1079	961	849	768	554	365	251
Texaco Canada Resources	2	2	2	2	1	1	1	1	1
Valley Pipe Line	570	540	511	489	461	433	351	251	187
Truck and Tank Car	1213	1194	1118	1053	991	932	778	588	447
Field Condensate	266	251	236	222	209	197	165	122	90
Alberta-Subtotal	17926	16852	15781	14420	13678	12475	9688	6757	5373
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	1718	2565	3465	4512	5385	7827	9989	10148
Alberta-Total	17926	18570	18346	17885	18190	17860	17515	16746	15521
Saskatchewan-Total[a]	115	115	115	114	112	110	101	90	68
Manitoba-Total	2	2	2	2	2	2	2	1	1
Frontier-Total	0	0	0	0	0	0	0	2700	6500
Canada-Total	18628	19318	19081	18604	18885	18551	18167	20035	22541

Note:[*] All or part of the production is entrained in an NGL mix.
[a] Includes field condensate.

Table A8-7
Propane Production from Refineries - Canada and Regions

(Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Atlantic	384	525	524	524	524	525	524	525	524
Quebec	613	668	667	667	667	668	667	668	667
Ontario	1475	1540	1536	1555	1594	1598	1594	1598	1594
Prairies	1103	1102	1178	1164	1149	1145	1157	1201	1228
British Columbia	307	311	256	256	256	256	256	256	256
Canada Total	**3882**	**4146**	**4161**	**4166**	**4190**	**4192**	**4198**	**4248**	**4269**

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Atlantic	384	525	524	524	524	525	524	525	524
Quebec	613	668	667	667	667	668	667	668	667
Ontario	1475	1540	1536	1555	1594	1598	1594	1598	1594
Prairies	1103	1116	1180	1185	1175	1179	1206	1268	1307
British Columbia	307	312	256	256	256	256	256	256	256
Canada Total	**3882**	**4161**	**4163**	**4187**	**4216**	**4226**	**4247**	**4315**	**4348**

Note: [a] Supply is net of energy supply industry own use.

Table A8-8
Butanes Production from Refineries - Canada and Regions

(Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Atlantic	315	431	430	430	430	431	430	431	430
Quebec	354	386	385	385	385	386	385	386	385
Ontario	1302	1360	1356	1373	1407	1411	1407	1410	1407
Prairies	1198	1197	1278	1263	1248	1243	1256	1304	1334
British Columbia	346	350	289	289	289	289	289	289	289
Canada Total	**3515**	**3724**	**3738**	**3740**	**3759**	**3760**	**3767**	**3820**	**3845**

High Case

	1987	1988	1989	1990	1991	1992	1995	2000	2005
Atlantic	315	431	430	430	430	431	430	431	430
Quebec	354	386	385	385	385	386	385	386	385
Ontario	1302	1360	1356	1373	1407	1411	1407	1410	1407
Prairies	1198	1212	1281	1286	1275	1280	1309	1377	1419
British Columbia	346	351	289	289	289	289	289	289	289
Canada Total	**3515**	**3740**	**3741**	**3763**	**3786**	**3797**	**3820**	**3893**	**3930**

Note: [a] Supply is net of energy supply industry own use.

Table A8-9
Ethane Supply and Demand - Canada

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Supply										
Total	**25.5**	**28.1**	**28.9**	**29.5**	**29.3**	**29.4**	**29.1**	**28.7**	**28.4**	**28.2**
Domestic Demand										
End Use	12.8	12.8	14.0	14.0	14.0	14.0	14.1	14.1	20.7	20.7
Miscible Fluid Requirements[a]	8.8	10.5	11.0	10.2	7.5	6.6	5.9	3.3	1.5	1.2
Total	**21.6**	**23.3**	**25.0**	**24.2**	**21.5**	**20.6**	**20.0**	**17.4**	**22.2**	**21.9**
Potential Exports	3.9	4.8	3.9	5.3	7.8	8.8	9.1	11.3	6.2	6.3

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply									
Total	**28.0**	**27.8**	**27.6**	**27.3**	**27.2**	**27.0**	**26.9**	**26.7**	**26.6**
Domestic Demand									
End Use	20.7	20.7	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Miscible Fluid Requirements[a]	0.7	0.6	0.4	0.0	0.0	0.0	0.0	0.0	0.0
Total	**21.4**	**21.3**	**21.2**	**20.8**	**20.8**	**20.8**	**20.8**	**20.8**	**20.8**
Potential Exports	6.6	6.5	6.4	6.5	6.4	6.2	6.1	5.9	5.8

High Case

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Supply										
Total	**25.5**	**28.2**	**29.2**	**30.0**	**30.0**	**30.2**	**29.9**	**29.6**	**29.3**	**28.9**
Domestic Demand										
End Use	12.8	12.8	14.0	14.0	14.0	14.0	14.1	14.1	20.7	20.7
Miscible Fluid Requirements[a]	8.8	10.5	11.3	10.5	8.4	8.1	7.0	5.0	4.1	3.8
Total	**21.6**	**23.3**	**25.3**	**24.5**	**22.4**	**22.1**	**21.1**	**19.1**	**24.8**	**24.5**
Potential Exports	3.9	4.9	3.9	5.5	7.6	8.1	8.8	10.5	4.5	4.4

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply									
Total	**28.5**	**28.1**	**27.7**	**27.3**	**27.1**	**27.0**	**26.8**	**26.7**	**26.6**
Domestic Demand									
End Use	20.7	20.7	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Miscible Fluid Requirements[a]	3.6	3.4	2.6	2.0	1.4	0.6	0.0	0.0	0.0
Total	**24.3**	**24.1**	**23.4**	**22.8**	**22.2**	**21.4**	**20.8**	**20.8**	**20.8**
Potential Exports	4.2	4.0	4.3	4.5	4.9	5.6	6.0	5.9	5.8

Note: [a] Miscible fluid requirements are net requirements after accounting for reproduced fluids from hydrocarbon miscible projects.

Table A8-10
Propane Supply and Demand - Canada

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Supply										
Total	**23.0**	**24.7**	**25.0**	**24.7**	**24.6**	**24.8**	**24.8**	**24.7**	**24.7**	**24.5**
Domestic Demand										
End Use	9.8	10.9	10.9	11.0	11.1	11.3	11.4	11.5	11.6	11.6
Miscible Fluid Requirements[a]	4.4	4.4	4.4	4.0	2.9	2.4	2.1	1.2	0.5	0.4
Total	**14.2**	**15.3**	**15.3**	**15.0**	**14.0**	**13.7**	**13.5**	**12.7**	**12.1**	**12.0**
Potential Exports	8.8	9.4	9.7	9.7	10.6	11.1	11.3	12.0	12.6	12.5

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply									
Total	**24.4**	**24.2**	**24.1**	**24.0**	**24.1**	**24.2**	**24.2**	**24.3**	**24.4**
Domestic Demand									
End Use	11.7	11.8	11.9	12.0	12.1	12.3	12.5	12.6	12.7
Miscible Fluid Requirements[a]	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Total	**11.9**	**12.0**	**12.0**	**12.0**	**12.1**	**12.3**	**12.5**	**12.6**	**12.7**
Potential Exports	12.5	12.2	12.1	12.0	12.0	11.9	11.7	11.7	11.7

High Case

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Supply										
Total	**23.0**	**24.9**	**25.4**	**25.3**	**25.5**	**25.7**	**25.9**	**26.0**	**26.1**	**26.0**
Domestic Demand										
End Use	9.8	11.0	11.1	11.4	11.6	11.8	12.0	12.2	12.4	12.6
Miscible Fluid Requirements[a]	4.4	4.4	4.6	4.2	3.3	3.1	2.6	1.8	1.4	1.3
Total	**14.2**	**15.4**	**15.7**	**15.6**	**14.9**	**14.9**	**14.6**	**14.0**	**13.8**	**13.9**
Potential Exports	8.8	9.5	9.7	9.7	10.6	10.8	11.3	12.0	12.3	12.1

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply									
Total	**25.9**	**25.8**	**25.7**	**25.6**	**25.5**	**25.4**	**25.3**	**25.4**	**25.6**
Domestic Demand									
End Use	12.7	12.8	13.0	13.1	13.3	13.5	13.7	13.9	14.0
Miscible Fluid Requirements[a]	1.3	1.2	0.9	0.7	0.5	0.2	0.0	0.0	0.0
Total	**14.0**	**14.0**	**13.9**	**13.8**	**13.8**	**13.7**	**13.7**	**13.9**	**14.0**
Potential Exports	11.9	11.8	11.8	11.8	11.7	11.7	11.6	11.5	11.6

Note: [a] Miscible fluid requirements are net requirements after accounting for reproduced fluids from hydrocarbon miscible projects.

Table A8-11
Butanes Supply and Demand - Canada

(Thousands of Cubic Metres per Day)

Low Case

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Supply										
Total	**14.0**	**14.8**	**15.2**	**15.0**	**15.0**	**15.1**	**15.1**	**15.0**	**15.0**	**14.9**
Domestic Demand										
End Use	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Refinery Requirements	3.1	2.9	3.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Miscible Fluid Requirements[a]	1.6	1.7	1.7	1.5	1.1	1.0	0.9	0.5	0.2	0.2
Total	**5.3**	**5.2**	**5.3**	**5.1**	**4.7**	**4.6**	**4.5**	**4.1**	**3.8**	**3.8**
Potential Exports	8.7	9.6	9.9	9.9	10.3	10.5	10.6	10.9	11.2	11.1

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply									
Total	**14.8**	**14.7**	**14.5**	**14.4**	**14.4**	**14.4**	**14.4**	**14.5**	**14.5**
Domestic Demand									
End Use	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Refinery Requirements	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
Miscible Fluid Requirements[a]	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Total	**3.7**	**3.7**	**3.8**	**3.7**	**3.7**	**3.8**	**3.8**	**3.8**	**3.8**
Potential Exports	11.1	11.0	10.7	10.7	10.7	10.6	10.6	10.7	10.7

High Case

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Supply										
Total	**14.0**	**14.9**	**15.4**	**15.5**	**15.5**	**15.6**	**15.7**	**15.7**	**15.8**	**15.8**
Domestic Demand										
End Use	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8
Refinery Requirements	3.1	2.9	3.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Miscible Fluid Requirements[a]	1.6	1.7	1.6	1.5	1.2	1.2	1.0	0.7	0.6	0.6
Total	**5.3**	**5.2**	**5.2**	**5.1**	**4.8**	**4.8**	**4.6**	**4.4**	**4.3**	**4.3**
Potential Exports	8.7	9.7	10.2	10.4	10.7	10.8	11.1	11.3	11.5	11.5

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply									
Total	**15.7**	**15.6**	**15.6**	**15.5**	**15.4**	**15.3**	**15.2**	**15.3**	**15.4**
Domestic Demand									
End Use	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Refinery Requirements	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Miscible Fluid Requirements[a]	0.5	0.5	0.4	0.3	0.2	0.1	0.0	0.0	0.0
Total	**4.2**	**4.2**	**4.2**	**4.1**	**4.0**	**3.9**	**3.8**	**3.9**	**3.9**
Potential Exports	11.5	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.5

Note: [a] Miscible fluid requirements are net requirements after accounting for reproduced fluids from hydrocarbon miscible projects.

Appendix 9

Table A9-1
Summarized Classification of Coal by Rank [a]

Class	Group	Volatile Matter[b] (percent)	Fixed Carbon[b] (percent)	Heat Content [c] (MJ/kg)
Anthracitic [d]	Meta-anthracite	<= 2	>=98	
	Anthracite	>2-8	92-<98	
	Semianthracite	>8-14	86-<92	
Bituminous [e]	Low Volatile Bituminous	>14-22	78-<86	
	Medium Volatile Bituminous	>22-31	69-<78	
	High Volatile A Bituminous	>31	<69	>=32.6
	High Volatile B Bituminous			30.2-<32.6
	High Volatile C Bituminous			26.7-<30.2
Subbituminous[f]	Subbituminous A			24.4-<26.7
	Subbituminous B			22.1-<24.4
	Subbituminous C			19.3-<22.1
Lignitic [g]	Lignite A			14.7-<19.3
	Lignite B			<14.7

Notes: [a] Lower rank coals are classified by heat content; higher ranks by volatile matter and fixed carbon.

[b] Dry, mineral-matter-free basis.

[c] Moist, mineral-matter-free basis.

[d] Non-agglomerating; if agglomerating classified as low volatile bituminous.

[e] Commonly agglomerating.

[f] If agglomerating is classified as high volatile C bituminous.

[g] Non-agglomerating.

Source: Coal Resources and Reserves of Canada, EMR Report ER-79, December, 1979.

Table A9-2
Summary of Canada's Coal Resources

(Megatonnes)

Coal Region	Coal Rank[a]	Immediate Interest Assurance[b,c] Measured	Indicated	Inferred	Future Interest Assurance Measured	Indicated	Inferred	Speculative
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Coastal British Columbia								
-Vancouver Island	h - mvb	35	80	200	-	-	300	-
-Queen Charlotte Islands	lvb - an	-	-	10	-	-	-	-
	h - mvb	-	15	10	-	-	-	-
	lig - sub	-	-	50	-	-	-	500
Intermontane British Columbia								
-Northern District	lvb - an	100	500	1000	-	-	-	4000
	h - mvb	30	50	100	-	-	-	100
-Southern District	sub - hvb	40	120	330	-	-	-	-
	lig - sub	450	320	270	-	-	-	-
Rocky Mountains and Foothills								
-Front Ranges								
East Kootenays	h - mvb	1390	1320	4040	-	2700	-	-
Crowsnest	m - lvb	265	140	510	-	200	-	-
	h - mvb	330	170	630	-	-	-	-
Cascade	lvb - an	240	120	455	-	210	-	-
Panther River-Clearwater	lvb - an	-	-	-	15	15	700	-
-Inner Foothills								
Southern District	m - lvb	635	320	1145	-	245	-	-
	h - mvb	150	75	275	-	-	-	-
Northern District	m - lvb	1115	2385	6270	-	100	-	-
-Outer Foothills	sub - hvb	830	740	1955	-	200	-	-
Plains								
-Mannville Group	lig - sub	-	35	100	-	-	30	-
-Belly River/Edmonton/Wapiti	sub - hvb	1240	585	1860	-	820	-	-
	lig - sub	11860	4935	16595	-	14115	-	-
-Paskapoo	sub - hvb	120	60	175	-	25	-	-
-Ravenscrag	lig - sub	1445	2680	3440	165	3910	23510	-
-Deep Coal	sub - hvb	-	-	-	1200	4000	50000	85000

Summary of Canada's Coal Resources

(Megatonnes)

Coal Region	Coal Rank[a]	Immediate Interest Assurance[b,c] Measured (1)	Indicated (2)	Inferred (3)	Future Interest Assurance Measured (4)	Indicated (5)	Inferred (6)	Speculative (7)
Hudson Bay Lowland								
-Onakawana	lig - sub	170	10	-		(No available estimates)		
Atlantic Provinces	h - mvb	345	365	770	-	1500	215	-
Northern Canada								
-Yukon/District of Mackenzie	lvb - an	-	-	90		(No available estimates of resources of future interest for this region)		
	h - mvb	-	-	150				
	sub - hvb	-	-	350				
	lig - sub	-	-	2290				
-Arctic Archipelago	sub - hvb	-	-	-	-	500	550	4500
	lig - sub	-	-	-	-	7000	7500	31000
Totals	lvb - an	340	620	1555	15	225	700	4000
	m - lvb	2015	2845	7925	-	545	-	-
	h - mvb	2280	2075	6175	-	4200	515	100
	sub - hvb	2230	1505	4670	1200	5545	50550	89500
	lig - sub	13925	7980	22745	165	25025	31040	31500

Notes: [a] an = anthracite; lvb = low volatile bituminous; mvb = medium volatile bituminous; hvb = high volatile bituminous; sub = subbituminous; lig = lignite.

[b] These coal resource estimates may differ from those of the respective provincial governments because of different resource estimating criteria and parameters used.

[c] Resources shown in this table include reserves.

Source: Geological Survey of Canada, 1988.

Table A9-3

Historical Data - Coal Production, Imports and Exports - Canada

(Megatonnes)

	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
Production										
Bituminous	6.1	5.4	5.0	8.0	9.7	11.4	12.3	12.5	15.8	14.4
Subbituminous	2.4	2.7	2.9	3.6	4.0	4.5	4.5	5.1	6.0	6.4
Lignite	1.8	2.0	1.8	3.5	3.0	3.0	3.7	3.5	3.5	4.7
Total	**10.3**	**10.2**	**9.7**	**15.1**	**16.7**	**18.8**	**20.5**	**21.1**	**25.3**	**25.5**
Imports	14.4	15.7	15.6	17.6	16.2	16.8	15.1	12.4	15.8	14.6
Exports	1.2	1.3	1.3	4.0	7.0	8.6	10.3	10.5	11.4	11.9

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Production										
Bituminous	15.3	17.1	18.4	20.2	21.7	22.3	22.6	32.1	34.3	32.2
Subbituminous	7.9	8.3	9.6	10.5	11.6	13.0	14.5	15.4	16.9	17.3
Lignite	5.5	5.1	5.0	6.0	6.8	7.5	7.8	9.9	9.7	8.3
Total	**28.7**	**30.5**	**33.0**	**36.7**	**40.1**	**42.8**	**44.8**	**57.4**	**60.9**	**57.8**
Imports	15.4	14.1	17.5	15.9	14.8	15.8	14.7	18.4	14.6	13.3
Exports	12.4	14.0	13.7	15.3	15.7	16.0	17.0	25.1	27.4	25.9

Source: Energy Statistics Handbook, Energy, Mines and Resources.

Table A9-4
Coal Supply and Demand - Canada

(Megatonnes)

Low Case

		1987	1988	1989	1990	1991	1992	1995	2000	2005
Production	Thermal	38.6	36.7	36.4	36	36.6	37.4	40.4	45.7	49.7
	Metallurgical	22.6	26.5	26.4	26.5	26.5	26.5	26.6	26.8	26.9
	Total	**61.2**	**63.2**	**62.8**	**62.5**	**63.1**	**63.9**	**67.0**	**72.5**	**76.6**
Imports	Thermal	8.5	6.1	4.9	4.2	6.5	5.6	6.8	9.4	11.1
	Metallurgical	5.8	6.0	6.2	6.2	6.6	6.9	7.2	8.1	9.1
	Total	**14.3**	**12.1**	**11.1**	**10.4**	**13.1**	**12.5**	**14.0**	**17.5**	**20.2**
Domestic Demand	Thermal	43.8	38.4	36.7	35.5	38.3	38.0	41.8	48.8	53.5
	Metallurgical	6.7	7.0	7.1	7.2	7.6	7.9	8.3	9.4	10.5
	Total	**50.5**	**45.4**	**43.8**	**42.7**	**45.9**	**45.9**	**50.1**	**58.2**	**64.0**
Exports	Thermal	4.3	4.4	4.6	4.7	4.8	5.0	5.4	6.3	7.3
	Metallurgical	22.4	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
	Total	**26.7**	**29.9**	**30.1**	**30.2**	**30.3**	**30.5**	**30.9**	**31.8**	**32.8**

High Case

		1987	1988	1989	1990	1991	1992	1995	2000	2005
Production	Thermal	38.6	37.5	37.7	39.1	41.3	43.6	49.7	61.6	72.7
	Metallurgical	22.6	26.5	26.6	26.9	26.9	27.2	27.7	28.6	29.4
	Total	**61.2**	**64.0**	**64.3**	**66.0**	**68.2**	**70.8**	**77.4**	**90.2**	**102.1**
Imports	Thermal	8.5	6.0	5.3	6.0	7.6	7.5	7.9	9.9	11.3
	Metallurgical	5.8	6.0	6.3	6.6	7.0	7.3	7.9	9.4	10.7
	Total	**14.3**	**12.0**	**11.6**	**12.6**	**14.6**	**14.8**	**15.8**	**19.3**	**22.0**
Domestic Demand	Thermal	43.8	39.0	38.3	40.1	43.7	45.6	51.2	63.4	73.6
	Metallurgical	6.7	7.0	7.3	7.7	8.0	8.5	9.2	10.9	12.3
	Total	**50.5**	**46.0**	**45.6**	**47.8**	**51.7**	**54.1**	**60.4**	**74.3**	**85.9**
Exports	Thermal	4.3	4.5	4.7	5.0	5.2	5.5	6.4	8.1	10.4
	Metallurgical	22.4	25.5	25.6	25.8	25.9	26.0	26.4	27.1	27.8
	Total	**26.7**	**30.0**	**30.3**	**30.8**	**31.1**	**31.5**	**32.8**	**35.2**	**38.2**

Table A10-1
Total Energy Balance

(Petajoules)	1980 History									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	459	32	3	338	498	0	78	0	0	1407
Commercial	301	15	1	257	203	1	0	0	0	779
Petrochemical	94	43	0	0	138	0	0	0	0	275
Industrial	728	14	248	504	509	42	368	0	0	2413
Transportation	0	2	0	2	1958	0	0	0	0	1962
Road	0	2	0	2	1541	0	0	0	0	1545
Rail	0	0	0	0	94	0	0	0	0	94
Air	0	0	0	0	172	0	0	0	0	172
Marine	0	0	0	0	151	0	0	0	0	151
Non-Energy Use	0	0	0	0	250	0	0	0	0	250
Total End Use	**1582**	**105**	**253**	**1101**	**3555**	**43**	**445**	**0**	**0**	**7085**
Own Use and Losses [e]	**134**	**15**	**0**	**115**	**268**	**0**	**0**	**0**	**0**	**532**
Conversions for Domestic Use [f]										
Electricity Generation	25	0	164	-1216	30	0	25	845	126	0
Refinery Propane Production	0	-35	0	0	35	0	0	0	0	0
Refinery Butanes Production	0	-24	0	0	24	0	0	0	0	0
Butane used in Refineries	0	38	0	0	-38	0	0	0	0	0
Steam Production	0	0	10	0	12	-43	0	0	21	0
NGL Production from Reprocessing	99	-99	0	0	0	0	0	0	0	0
Total Conversions	**125**	**-120**	**174**	**-1216**	**64**	**-43**	**25**	**845**	**147**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	59	0	383	0	74	0	0	0	308	824
Coke Production	0	0	13	0	0	0	0	0	0	13
Steam Production	0	0	0	0	0	0	0	0	1	2
Total Conversion Losses	**59**	**0**	**396**	**0**	**74**	**0**	**0**	**0**	**308**	**838**
Domestic Demand for Primary Energy	**1900**	**0**	**823**	**0**	**3961**	**0**	**470**	**845**	**455**	**8455**
Export Demand										
Total Energy Exports	863	222	450	109	742	0	0	0	0	2386
Conversions for Export										
Electricity	0	0	39	-109	11	0	0	59	0	0
NGL Production Reprocessing	56	-56	0	0	0	0	0	0	0	0
Total Conversions	56	-56	39	-109	11	0	0	59	0	0
Conversion Losses-Export										
Electricity Generation	0	0	66	0	16	0	0	0	0	82
Export Demand for Primary Energy [g]	**919**	**166**	**555**	**0**	**770**	**0**	**0**	**59**	**0**	**2469**
Total Primary Demand [h]	**2819**	**166**	**1378**	**0**	**4731**	**0**	**470**	**904**	**455**	**10924**
Primary Domestic Production	**2764**	**161**	**891**	**0**	**3444**	**0**	**470**	**904**	**455**	**9090**
Primary Energy Imports [h]	**0**	**0**	**476**	**0**	**1344**	**0**	**0**	**0**	**0**	**1820**
Total Primary Supply [i]	**2764**	**161**	**1367**	**0**	**4788**	**0**	**470**	**904**	**455**	**10910**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
	1986 History									
Domestic Demand										
End Use										
Residential	525	32	4	428	274	0	111	0	0	1374
Commercial	386	15	1	326	104	1	1	0	0	833
Petrochemical	149	99	0	0	127	0	0	0	0	375
Industrial	796	16	237	633	313	32	409	0	0	2434
Transportation	1	17	0	3	1726	0	0	0	0	1747
Road	1	17	0	3	1413	0	0	0	0	1435
Rail	0	0	0	0	75	0	0	0	0	75
Air	0	0	0	0	162	0	0	0	0	162
Marine	0	0	0	0	75	0	0	0	0	75
Non-Energy Use	0	0	0	0	223	0	0	0	0	223
Total End Use	**1856**	**179**	**241**	**1389**	**2766**	**32**	**522**	**0**	**0**	**6986**
Own Use and Losses [e]	**147**	**10**	**3**	**114**	**201**	**0**	**0**	**0**	**0**	**475**
Conversions for Domestic Use [f]										
Electricity Generation	20	0	211	-1503	19	0	18	1023	212	0
Refinery Propane Production	0	-34	0	0	34	0	0	0	0	0
Refinery Butanes Production	0	-24	0	0	24	0	0	0	0	0
Butane used in Refineries	0	27	0	0	-27	0	0	0	0	0
Steam Production	1	0	1	0	2	-32	0	0	28	0
NGL Production from Reprocessing	158	-158	0	0	0	0	0	0	0	0
Total Conversions	**179**	**-189**	**212**	**-1503**	**52**	**-32**	**18**	**1023**	**240**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	40	0	528	0	24	0	0	0	563	1154
Coke Production	0	0	-1	0	0	0	0	0	0	-1
Steam Production	0	0	0	0	0	0	0	0	0	0
Total Conversion Losses	**40**	**0**	**527**	**0**	**24**	**0**	**0**	**0**	**563**	**1153**
Domestic Demand for Primary Energy	**2222**	**0**	**983**	**0**	**3042**	**0**	**540**	**1023**	**803**	**8614**
Export Demand										
Total Energy Exports	794	132	759	140	1633	0	0	0	0	3458
Conversions for Export										
Electricity	0	0	37	-140	2	0	0	88	13	0
NGL Production Reprocessing	25	-25	0	0	0	0	0	0	0	0
Total Conversions	25	-25	37	-140	2	0	0	88	13	0
Conversion Losses-Export										
Electricity Generation	0	0	20	0	15	0	0	0	25	59
Export Demand for Primary Energy [g]	**819**	**107**	**816**	**0**	**1649**	**0**	**0**	**88**	**38**	**3517**
Total Primary Demand [h]	**3041**	**107**	**1799**	**0**	**4692**	**0**	**540**	**1111**	**842**	**12131**
Primary Domestic Production	**2905**	**113**	**1382**	**0**	**3531**	**0**	**540**	**1111**	**842**	**10424**
Primary Energy Imports [h]	**0**	**0**	**416**	**0**	**1061**	**0**	**0**	**0**	**0**	**1477**
Total Primary Supply [i]	**2905**	**113**	**1798**	**0**	**4592**	**0**	**540**	**1111**	**842**	**11901**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules)	1987 History									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	506	31	4	443	256	0	107	0	0	1347
Commercial	370	15	1	337	101	1	1	0	0	826
Petrochemical	159	104	0	0	151	0	0	0	0	414
Industrial	785	15	255	654	326	30	420	0	0	2485
Transportation	2	18	0	3	1768	0	0	0	0	1791
Road	2	18	0	3	1437	0	0	0	0	1460
Rail	0	0	0	0	84	0	0	0	0	84
Air	0	0	0	0	173	0	0	0	0	173
Marine	0	0	0	0	74	0	0	0	0	74
Non-Energy Use	0	0	0	0	249	0	0	0	0	249
Total End Use	**1824**	**183**	**259**	**1437**	**2850**	**31**	**529**	**0**	**0**	**7113**
Own Use and Losses [e]	**156**	**10**	**5**	**124**	**209**	**0**	**0**	**0**	**0**	**504**
Conversions for Domestic Use [f]										
Electricity Generation	21	0	258	-1561	26	0	20	998	237	0
Refinery Propane Production	0	-36	0	0	36	0	0	0	0	0
Refinery Butanes Production	0	-36	0	0	36	0	0	0	0	0
Butane used in Refineries	0	32	0	0	-32	0	0	0	0	0
Steam Production	1	0	0	0	2	-31	0	0	28	0
NGL Production from Reprocessing	154	-154	0	0	0	0	0	0	0	0
Total Conversions	**176**	**-194**	**258**	**-1561**	**68**	**-31**	**20**	**998**	**266**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	45	0	554	0	48	0	0	0	609	1256
Coke Production	0	0	11	0	0	0	0	0	0	11
Steam Production	0	0	0	0	0	0	0	0	7	8
Total Conversion Losses	**45**	**0**	**565**	**0**	**48**	**0**	**0**	**0**	**609**	**1267**
Domestic Demand for Primary Energy	**2200**	**0**	**1087**	**0**	**3175**	**0**	**548**	**998**	**875**	**8883**
Export Demand										
Total Energy Exports	1060	199	737	171	1784	0	0	0	0	3951
Conversions for Export										
Electricity	0	0	36	-171	1	0	0	126	7	0
NGL Production Reprocessing	45	-45	0	0	0	0	0	0	0	0
Total Conversions	45	-45	36	-171	1	0	0	126	7	0
Conversion Losses-Export Electricity Generation	0	0	60	0	5	0	0	0	20	85
Export Demand for Primary Energy [g]	**1105**	**154**	**833**	**0**	**1791**	**0**	**0**	**126**	**28**	**4036**
Total Primary Demand [h]	**3305**	**154**	**1920**	**0**	**4966**	**0**	**548**	**1124**	**903**	**12919**
Primary Domestic Production	**3303**	**153**	**1505**	**0**	**3821**	**0**	**548**	**1124**	**903**	**11357**
Primary Energy Imports [h]	**0**	**0**	**415**	**0**	**1225**	**0**	**0**	**0**	**0**	**1640**
Total Primary Supply [i]	**3303**	**153**	**1920**	**0**	**5046**	**0**	**548**	**1124**	**903**	**12997**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	1988 Low Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	544	32	4	467	245	0	112	0	0	1404
Commercial	390	16	1	343	98	1	2	0	0	849
Petrochemical	159	112	0	0	165	0	0	0	0	436
Industrial	795	15	263	657	336	28	429	0	0	2524
Transportation	3	19	0	3	1785	0	0	0	0	1809
Road	3	19	0	3	1440	0	0	0	0	1464
Rail	0	0	0	0	85	0	0	0	0	85
Air	0	0	0	0	181	0	0	0	0	181
Marine	0	0	0	0	79	0	0	0	0	79
Non-Energy Use	0	0	0	0	249	0	0	0	0	249
Total End Use	**1890**	**194**	**267**	**1471**	**2878**	**29**	**543**	**0**	**0**	**7273**
Own Use and Losses [e]	**173**	**12**	**5**	**123**	**210**	**0**	**0**	**0**	**0**	**523**
Conversions for Domestic Use [f]										
Electricity Generation	20	0	221	-1594	20	0	22	1035	276	0
Refinery Propane Production	0	-38	0	0	38	0	0	0	0	0
Refinery Butanes Production	0	-39	0	0	39	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	1	0	0	0	1	-29	0	0	27	0
NGL Production from Reprocessing	159	-159	0	0	0	0	0	0	0	0
Total Conversions	**180**	**-206**	**221**	**-1594**	**69**	**-29**	**22**	**1035**	**303**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	46	0	458	0	39	0	0	0	716	1260
Coke Production	0	0	11	0	0	0	0	0	0	11
Steam Production	0	0	0	0	0	0	0	0	7	7
Total Conversion Losses	**46**	**0**	**469**	**0**	**39**	**0**	**0**	**0**	**716**	**1271**
Domestic Demand for Primary Energy	**2289**	**0**	**963**	**0**	**3196**	**0**	**565**	**1035**	**1020**	**9067**
Export Demand										
Total Energy Exports	1362	220	825	141	1987	0	0	0	0	4535
Conversions for Export										
Electricity	0	0	28	-141	1	0	0	101	10	0
NGL Production Reprocessing	65	-65	0	0	0	0	0	0	0	0
Total Conversions	65	-65	28	-141	1	0	0	101	10	0
Conversion Losses-Export										
Electricity Generation	0	0	54	0	3	0	0	0	22	79
Export Demand for Primary Energy [g]	**1427**	**155**	**908**	**0**	**1991**	**0**	**0**	**101**	**32**	**4615**
Total Primary Demand [h]	**3717**	**155**	**1871**	**0**	**5187**	**0**	**565**	**1136**	**1052**	**13682**
Primary Domestic Production	**3724**	**155**	**1520**	**0**	**3870**	**0**	**565**	**1136**	**1052**	**12022**
Primary Energy Imports [h]	**0**	**0**	**351**	**0**	**1320**	**0**	**0**	**0**	**0**	**1670**
Total Primary Supply [i]	**3724**	**155**	**1871**	**0**	**5190**	**0**	**565**	**1136**	**1052**	**13692**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules) — 1988 — High Case

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	541	32	4	465	244	0	112	0	0	1398
Commercial	391	16	1	343	96	1	2	0	0	849
Petrochemical	159	112	0	0	165	0	0	0	0	436
Industrial	829	16	264	665	326	29	429	0	0	2558
Transportation	3	19	0	3	1777	0	0	0	0	1802
Road	3	19	0	3	1436	0	0	0	0	1461
Rail	0	0	0	0	85	0	0	0	0	85
Air	0	0	0	0	178	0	0	0	0	178
Marine	0	0	0	0	78	0	0	0	0	78
Non-Energy Use	0	0	0	0	250	0	0	0	0	250
Total End Use	**1924**	**195**	**269**	**1477**	**2859**	**29**	**542**	**0**	**0**	**7294**
Own Use and Losses [e]	**175**	**12**	**5**	**124**	**209**	**0**	**0**	**0**	**0**	**524**
Conversions for Domestic Use [f]										
Electricity Generation	22	0	224	-1600	21	0	22	1035	276	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-39	0	0	39	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	1	0	0	0	1	-29	0	0	27	0
NGL Production from Reprocessing	159	-159	0	0	0	0	0	0	0	0
Total Conversions	**181**	**-207**	**224**	**-1600**	**70**	**-29**	**22**	**1035**	**304**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	49	0	466	0	41	0	0	0	716	1273
Coke Production	0	0	11	0	0	0	0	0	0	11
Steam Production	0	0	0	0	0	0	0	0	7	7
Total Conversion Losses	**49**	**0**	**477**	**0**	**41**	**0**	**0**	**0**	**716**	**1284**
Domestic Demand for Primary Energy	**2329**	**0**	**975**	**0**	**3179**	**0**	**564**	**1035**	**1020**	**9101**
Export Demand										
Total Energy Exports	1362	223	828	142	2059	0	0	0	0	4614
Conversions for Export										
Electricity	0	0	28	-142	1	0	0	102	10	0
NGL Production Reprocessing	63	-63	0	0	0	0	0	0	0	0
Total Conversions	63	-63	28	-142	1	0	0	102	10	0
Conversion Losses-Export										
Electricity Generation	0	0	54	0	3	0	0	0	23	79
Export Demand for Primary Energy [g]	**1426**	**160**	**911**	**0**	**2063**	**0**	**0**	**102**	**32**	**4693**
Total Primary Demand [h]	**3754**	**160**	**1886**	**0**	**5242**	**0**	**564**	**1137**	**1052**	**13795**
Primary Domestic Production	**3754**	**160**	**1538**	**0**	**3974**	**0**	**564**	**1137**	**1052**	**12179**
Primary Energy Imports [h]	**0**	**0**	**348**	**0**	**1273**	**0**	**0**	**0**	**0**	**1621**
Total Primary Supply [i]	**3754**	**160**	**1886**	**0**	**5247**	**0**	**564**	**1137**	**1052**	**13800**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	1989 Low Case									
	Natural Gas	**NGL [a]**	**Coal, Coke Coke Gas**	**Electricity**	**Oil [b]**	**Steam**	**Renewable**	**Hydro [c]**	**Nuclear [d]**	**Total**
Domestic Demand										
End Use										
Residential	548	32	3	477	237	0	115	0	0	1411
Commercial	398	16	1	345	98	1	2	0	0	860
Petrochemical	159	120	0	0	168	0	0	0	0	448
Industrial	818	15	269	654	337	27	435	0	0	2555
Transportation	3	19	0	4	1797	0	0	0	0	1823
Road	3	19	0	4	1444	0	0	0	0	1469
Rail	0	0	0	0	88	0	0	0	0	88
Air	0	0	0	0	184	0	0	0	0	184
Marine	0	0	0	0	82	0	0	0	0	82
Non-Energy Use	0	0	0	0	253	0	0	0	0	253
Total End Use	**1927**	**202**	**273**	**1479**	**2890**	**27**	**552**	**0**	**0**	7350
Own Use and Losses [e]	**178**	**12**	**6**	**124**	**210**	**0**	**0**	**0**	**0**	530
Conversions for Domestic Use [f]										
Electricity Generation	21	0	208	-1603	18	0	24	1037	295	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-39	0	0	39	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	1	0	0	0	1	-27	0	0	26	0
NGL Production from Reprocessing	167	-167	0	0	0	0	0	0	0	0
Total Conversions	**188**	**-214**	**208**	**-1603**	**66**	**-27**	**24**	**1037**	**321**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	50	0	438	0	36	0	0	0	763	1287
Coke Production	0	0	11	0	0	0	0	0	0	11
Steam Production	0	0	0	0	0	0	0	0	6	7
Total Conversion Losses	**50**	**0**	**449**	**0**	**36**	**0**	**0**	**0**	**763**	1299
Domestic Demand for Primary Energy	**2344**	**0**	**935**	**0**	**3202**	**0**	**576**	**1037**	**1084**	9178
Export Demand										
Total Energy Exports	1416	220	831	141	1900	0	0	0	0	4508
Conversions for Export										
Electricity	0	0	25	-141	1	0	0	102	13	0
NGL Production Reprocessing	63	-63	0	0	0	0	0	0	0	0
Total Conversions	63	-63	25	-141	1	0	0	102	13	0
Conversion Losses-Export										
Electricity Generation	0	0	48	0	3	0	0	0	30	81
Export Demand for Primary Energy [g]	**1479**	**157**	**904**	**0**	**1904**	**0**	**0**	**102**	**43**	4588
Total Primary Demand [h]	**3822**	**157**	**1838**	**0**	**5106**	**0**	**576**	**1139**	**1128**	13767
Primary Domestic Production	**3828**	**157**	**1517**	**0**	**3812**	**0**	**576**	**1139**	**1128**	12156
Primary Energy Imports [h]	**0**	**0**	**322**	**0**	**1383**	**0**	**0**	**0**	**0**	1704
Total Primary Supply [i]	**3828**	**157**	**1838**	**0**	**5195**	**0**	**576**	**1139**	**1128**	13860

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Total Energy Balance

(Petajoules)	1989 High Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	545	32	3	474	236	0	114	0	0	1405
Commercial	403	16	1	345	96	1	2	0	0	863
Petrochemical	159	120	0	0	168	0	0	0	0	448
Industrial	894	16	277	677	325	28	437	0	0	2653
Transportation	4	20	0	4	1788	0	0	0	0	1816
Road	4	20	0	4	1440	0	0	0	0	1467
Rail	0	0	0	0	87	0	0	0	0	87
Air	0	0	0	0	182	0	0	0	0	182
Marine	0	0	0	0	80	0	0	0	0	80
Non-Energy Use	0	0	0	0	254	0	0	0	0	254
Total End Use	**2006**	**204**	**281**	**1500**	**2867**	**28**	**553**	**0**	**0**	**7439**
Own Use and Losses [e]	**183**	**12**	**6**	**125**	**209**	**0**	**0**	**0**	**0**	**535**
Conversions for Domestic Use [f]										
Electricity Generation	23	0	217	-1625	21	0	24	1044	296	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-39	0	0	39	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	1	0	0	0	1	-28	0	0	26	0
NGL Production from Reprocessing	169	-169	0	0	0	0	0	0	0	0
Total Conversions	**193**	**-216**	**217**	**-1625**	**70**	**-28**	**24**	**1044**	**323**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	55	0	457	0	42	0	0	0	765	1320
Coke Production	0	0	12	0	0	0	0	0	0	12
Steam Production	0	0	0	0	0	0	0	0	7	7
Total Conversion Losses	**55**	**0**	**469**	**0**	**42**	**0**	**0**	**0**	**765**	**1332**
Domestic Demand for Primary Energy	**2437**	**0**	**973**	**0**	**3189**	**0**	**577**	**1044**	**1087**	**9306**
Export Demand										
Total Energy Exports	1416	223	836	141	2097	0	0	0	0	4713
Conversions for Export										
Electricity	0	0	26	-141	1	0	0	102	12	0
NGL Production Reprocessing	60	-60	0	0	0	0	0	0	0	0
Total Conversions	60	-60	26	-141	1	0	0	102	12	0
Conversion Losses-Export										
Electricity Generation	0	0	49	0	3	0	0	0	29	80
Export Demand for Primary Energy [g]	**1476**	**163**	**911**	**0**	**2101**	**0**	**0**	**102**	**41**	**4793**
Total Primary Demand [h]	**3913**	**163**	**1884**	**0**	**5289**	**0**	**577**	**1145**	**1128**	**14099**
Primary Domestic Production	**3911**	**163**	**1548**	**0**	**4018**	**0**	**577**	**1145**	**1128**	**12490**
Primary Energy Imports [h]	**0**	**0**	**336**	**0**	**1322**	**0**	**0**	**0**	**0**	**1658**
Total Primary Supply [i]	**3911**	**163**	**1884**	**0**	**5340**	**0**	**577**	**1145**	**1128**	**14148**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	1990 Low Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	554	32	3	483	232	0	115	0	0	1418
Commercial	407	16	0	351	96	1	2	0	0	873
Petrochemical	166	123	0	0	169	0	0	0	0	457
Industrial	828	15	271	649	329	25	443	0	0	2561
Transportation	4	19	0	4	1808	0	0	0	0	1835
Road	4	19	0	4	1451	0	0	0	0	1478
Rail	0	0	0	0	88	0	0	0	0	88
Air	0	0	0	0	185	0	0	0	0	185
Marine	0	0	0	0	84	0	0	0	0	84
Non-Energy Use	0	0	0	0	257	0	0	0	0	257
Total End Use	**1959**	**204**	**275**	**1487**	**2891**	**25**	**560**	**0**	**0**	**7402**
Own Use and Losses [e]	**181**	**12**	**6**	**127**	**211**	**0**	**0**	**0**	**0**	**537**
Conversions for Domestic Use [f]										
Electricity Generation	20	0	199	-1614	21	0	28	1042	305	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-39	0	0	39	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	1	0	0	0	1	-25	0	0	23	0
NGL Production from Reprocessing	169	-169	0	0	0	0	0	0	0	0
Total Conversions	**190**	**-216**	**199**	**-1614**	**69**	**-25**	**28**	**1042**	**328**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	51	0	417	0	42	0	0	0	782	1292
Coke Production	0	0	11	0	0	0	0	0	0	11
Steam Production	0	0	0	0	0	0	0	0	6	6
Total Conversion Losses	**51**	**0**	**428**	**0**	**42**	**0**	**0**	**0**	**782**	**1303**
Domestic Demand for Primary Energy	**2380**	**0**	**908**	**0**	**3214**	**0**	**588**	**1042**	**1110**	**9243**
Export Demand										
Total Energy Exports	1440	229	834	159	1836	0	0	0	0	4498
Conversions for Export										
Electricity	0	0	24	-159	1	0	0	119	14	0
NGL Production Reprocessing	65	-65	0	0	0	0	0	0	0	0
Total Conversions	65	-65	24	-159	1	0	0	119	14	0
Conversion Losses-Export										
Electricity Generation	0	0	46	0	3	0	0	0	35	83
Export Demand for Primary Energy [g]	**1505**	**164**	**904**	**0**	**1840**	**0**	**0**	**119**	**49**	**4581**
Total Primary Demand [h]	**3885**	**164**	**1812**	**0**	**5054**	**0**	**588**	**1161**	**1159**	**13824**
Primary Domestic Production	**3892**	**163**	**1510**	**0**	**3747**	**0**	**588**	**1161**	**1159**	**12222**
Primary Energy Imports [h]	**0**	**0**	**301**	**0**	**1404**	**0**	**0**	**0**	**0**	**1705**
Total Primary Supply [i]	**3892**	**163**	**1812**	**0**	**5151**	**0**	**588**	**1161**	**1159**	**13927**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules) — 1990 — High Case

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	553	32	3	481	232	0	114	0	0	1415
Commercial	419	16	0	352	93	1	2	0	0	883
Petrochemical	166	123	0	0	169	0	0	0	0	457
Industrial	974	16	290	699	324	27	446	0	0	2777
Transportation	5	21	0	4	1802	0	0	0	0	1832
Road	5	21	0	4	1449	0	0	0	0	1479
Rail	0	0	0	0	88	0	0	0	0	88
Air	0	0	0	0	184	0	0	0	0	184
Marine	0	0	0	0	82	0	0	0	0	82
Non-Energy Use	0	0	0	0	260	0	0	0	0	260
Total End Use	**2116**	**207**	**294**	**1536**	**2880**	**27**	**563**	**0**	**0**	**7624**
Own Use and Losses [e]	**190**	**13**	**6**	**130**	**212**	**0**	**0**	**0**	**0**	**551**
Conversions for Domestic Use [f]										
Electricity Generation	22	0	232	-1666	26	0	28	1051	307	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-40	0	0	40	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	1	0	0	0	1	-27	0	0	26	0
NGL Production from Reprocessing	172	-172	0	0	0	0	0	0	0	0
Total Conversions	**195**	**-220**	**232**	**-1666**	**76**	**-27**	**28**	**1051**	**332**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	56	0	482	0	54	0	0	0	788	1381
Coke Production	0	0	12	0	0	0	0	0	0	12
Steam Production	0	0	0	0	0	0	0	0	6	7
Total Conversion Losses	**56**	**0**	**495**	**0**	**54**	**0**	**0**	**0**	**788**	**1393**
Domestic Demand for Primary Energy	**2557**	**0**	**1027**	**0**	**3222**	**0**	**591**	**1051**	**1120**	**9568**
Export Demand										
Total Energy Exports	1440	236	850	158	2183	0	0	0	0	4867
Conversions for Export										
Electricity	0	0	26	-158	1	0	0	118	12	0
NGL Production Reprocessing	73	-73	0	0	0	0	0	0	0	0
Total Conversions	73	-73	26	-158	1	0	0	118	12	0
Conversion Losses-Export										
Electricity Generation	0	0	50	0	3	0	0	0	29	82
Export Demand for Primary Energy [g]	**1513**	**163**	**927**	**0**	**2187**	**0**	**0**	**118**	**41**	**4949**
Total Primary Demand [h]	**4070**	**163**	**1954**	**0**	**5409**	**0**	**591**	**1169**	**1161**	**14517**
Primary Domestic Production	**4069**	**163**	**1589**	**0**	**4132**	**0**	**591**	**1169**	**1161**	**12874**
Primary Energy Imports [h]	**0**	**0**	**365**	**0**	**1354**	**0**	**0**	**0**	**0**	**1719**
Total Primary Supply [i]	**4069**	**163**	**1954**	**0**	**5486**	**0**	**591**	**1169**	**1161**	**14593**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	1991 Low Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	562	32	3	496	225	0	118	0	0	1436
Commercial	416	16	0	355	96	0	2	0	0	887
Petrochemical	166	123	0	0	171	0	0	0	0	460
Industrial	857	15	290	668	336	24	447	0	0	2637
Transportation	5	19	0	4	1827	0	0	0	0	1856
Road	5	19	0	4	1467	0	0	0	0	1495
Rail	0	0	0	0	89	0	0	0	0	89
Air	0	0	0	0	186	0	0	0	0	186
Marine	0	0	0	0	85	0	0	0	0	85
Non-Energy Use	0	0	0	0	263	0	0	0	0	263
Total End Use	**2005**	**205**	**294**	**1523**	**2920**	**24**	**567**	**0**	**0**	**7539**
Own Use and Losses [e]	**187**	**13**	**7**	**132**	**214**	**0**	**0**	**0**	**0**	**552**
Conversions for Domestic Use [f]										
Electricity Generation	20	0	232	-1655	29	0	31	1036	307	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-40	0	0	40	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	0	0	0	0	1	-24	0	0	23	0
NGL Production from Reprocessing	169	-169	0	0	0	0	0	0	0	0
Total Conversions	**189**	**-218**	**232**	**-1655**	**79**	**-24**	**31**	**1036**	**330**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	53	0	458	0	59	0	0	0	791	1361
Coke Production	0	0	12	0	0	0	0	0	0	12
Steam Production	0	0	0	0	0	0	0	0	6	6
Total Conversion Losses	**53**	**0**	**470**	**0**	**59**	**0**	**0**	**0**	**791**	**1373**
Domestic Demand for Primary Energy	**2434**	**0**	**1003**	**0**	**3272**	**0**	**598**	**1036**	**1121**	**9464**
Export Demand										
Total Energy Exports	1471	259	836	175	1700	0	0	0	0	4441
Conversions for Export										
Electricity	0	0	27	-175	1	0	0	136	10	0
NGL Production Reprocessing	71	-71	0	0	0	0	0	0	0	0
Total Conversions	71	-71	27	-175	1	0	0	136	10	0
Conversion Losses-Export										
Electricity Generation	0	0	63	0	3	0	0	0	28	93
Export Demand for Primary Energy [g]	**1543**	**188**	**926**	**0**	**1704**	**0**	**0**	**136**	**38**	**4534**
Total Primary Demand [h]	**3977**	**188**	**1928**	**0**	**4977**	**0**	**598**	**1172**	**1159**	**13998**
Primary Domestic Production	**3983**	**187**	**1548**	**0**	**3621**	**0**	**598**	**1172**	**1159**	**12267**
Primary Energy Imports [h]	**0**	**0**	**380**	**0**	**1403**	**0**	**0**	**0**	**0**	**1783**
Total Primary Supply [i]	**3983**	**187**	**1928**	**0**	**5024**	**0**	**598**	**1172**	**1159**	**14050**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules)	1991 High Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	565	32	3	494	221	0	117	0	0	1432
Commercial	433	16	0	358	91	0	2	0	0	901
Petrochemical	166	123	0	0	171	0	0	0	0	460
Industrial	1035	17	310	725	329	26	451	0	0	2893
Transportation	6	22	0	4	1822	0	0	0	0	1854
Road	6	22	0	4	1465	0	0	0	0	1497
Rail	0	0	0	0	89	0	0	0	0	89
Air	0	0	0	0	185	0	0	0	0	185
Marine	0	0	0	0	82	0	0	0	0	82
Non-Energy Use	0	0	0	0	267	0	0	0	0	267
Total End Use	**2204**	**210**	**314**	**1581**	**2901**	**27**	**570**	**0**	**0**	**7807**
Own Use and Losses [e]	**197**	**13**	**7**	**134**	**216**	**0**	**0**	**0**	**0**	**567**
Conversions for Domestic Use [f]										
Electricity Generation	22	0	264	-1715	39	0	31	1048	311	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-40	0	0	40	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	0	0	0	0	1	-27	0	0	25	0
NGL Production from Reprocessing	174	-174	0	0	0	0	0	0	0	0
Total Conversions	**196**	**-223**	**264**	**-1715**	**89**	**-27**	**31**	**1048**	**336**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	57	0	537	0	80	0	0	0	788	1462
Coke Production	0	0	13	0	0	0	0	0	0	13
Steam Production	0	0	0	0	0	0	0	0	6	7
Total Conversion Losses	**57**	**0**	**550**	**0**	**80**	**0**	**0**	**0**	**788**	**1475**
Domestic Demand for Primary Energy	**2655**	**0**	**1134**	**0**	**3286**	**0**	**601**	**1048**	**1124**	**9848**
Export Demand										
Total Energy Exports	1471	261	858	159	2139	0	0	0	0	4889
Conversions for Export										
Electricity	0	0	23	-159	1	0	0	126	9	0
NGL Production Reprocessing	79	-79	0	0	0	0	0	0	0	0
Total Conversions	79	-79	23	-159	1	0	0	126	9	0
Conversion Losses-Export										
Electricity Generation	0	0	53	0	3	0	0	0	27	83
Export Demand for Primary Energy [g]	**1551**	**182**	**934**	**0**	**2143**	**0**	**0**	**126**	**37**	**4972**
Total Primary Demand [h]	**4205**	**182**	**2068**	**0**	**5429**	**0**	**601**	**1174**	**1161**	**14820**
Primary Domestic Production	**4205**	**182**	**1645**	**0**	**4123**	**0**	**601**	**1174**	**1161**	**13091**
Primary Energy Imports [h]	**0**	**0**	**423**	**0**	**1381**	**0**	**0**	**0**	**0**	**1804**
Total Primary Supply [i]	**4205**	**182**	**2068**	**0**	**5504**	**0**	**601**	**1174**	**1161**	**14895**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	1992 Low Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	572	32	3	505	222	0	119	0	0	1454
Commercial	428	16	0	361	96	0	2	0	0	904
Petrochemical	166	124	0	0	174	0	0	0	0	464
Industrial	885	15	304	689	339	23	450	0	0	2705
Transportation	5	20	0	4	1846	0	0	0	0	1876
Road	5	20	0	4	1484	0	0	0	0	1514
Rail	0	0	0	0	90	0	0	0	0	90
Air	0	0	0	0	186	0	0	0	0	186
Marine	0	0	0	0	86	0	0	0	0	86
Non-Energy Use	0	0	0	0	270	0	0	0	0	270
Total End Use	**2056**	**206**	**308**	**1559**	**2947**	**23**	**572**	**0**	**0**	**7672**
Own Use and Losses [e]	**192**	**13**	**7**	**133**	**217**	**0**	**0**	**0**	**0**	**562**
Conversions for Domestic Use [f]										
Electricity Generation	21	0	225	-1692	31	0	38	1050	328	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-40	0	0	40	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	0	0	0	0	1	-23	0	0	22	0
NGL Production from Reprocessing	170	-170	0	0	0	0	0	0	0	0
Total Conversions	**191**	**-219**	**225**	**-1692**	**81**	**-23**	**38**	**1050**	**350**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	55	0	469	0	65	0	0	0	832	1420
Coke Production	0	0	13	0	0	0	0	0	0	13
Steam Production	0	0	0	0	0	0	0	0	5	6
Total Conversion Losses	**55**	**0**	**481**	**0**	**65**	**0**	**0**	**0**	**832**	**1433**
Domestic Demand for Primary Energy	**2494**	**0**	**1021**	**0**	**3310**	**0**	**610**	**1050**	**1182**	**9666**
Export Demand										
Total Energy Exports	1498	272	842	171	1574	0	0	0	0	4357
Conversions for Export										
Electricity	0	0	20	-171	1	0	0	136	14	0
NGL Production Reprocessing	76	-76	0	0	0	0	0	0	0	0
Total Conversions	76	-76	20	-171	1	0	0	136	14	0
Conversion Losses-Export										
Electricity Generation	0	0	47	0	3	0	0	0	39	89
Export Demand for Primary Energy [g]	**1574**	**196**	**909**	**0**	**1578**	**0**	**0**	**136**	**53**	**4446**
Total Primary Demand [h]	**4068**	**196**	**1930**	**0**	**4888**	**0**	**610**	**1185**	**1235**	**14113**
Primary Domestic Production	**4081**	**197**	**1567**	**0**	**3498**	**0**	**610**	**1185**	**1235**	**12373**
Primary Energy Imports [h]	**0**	**0**	**363**	**0**	**1461**	**0**	**0**	**0**	**0**	**1824**
Total Primary Supply [i]	**4081**	**197**	**1930**	**0**	**4959**	**0**	**610**	**1185**	**1235**	**14197**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules)

1992

High Case

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	575	32	3	504	213	0	118	0	0	1445
Commercial	445	17	0	366	89	0	3	0	0	919
Petrochemical	166	124	0	0	174	0	0	0	0	464
Industrial	1091	17	328	762	336	26	455	0	0	3016
Transportation	7	23	0	5	1844	0	0	0	0	1878
Road	7	23	0	5	1484	0	0	0	0	1517
Rail	0	0	0	0	90	0	0	0	0	90
Air	0	0	0	0	187	0	0	0	0	187
Marine	0	0	0	0	82	0	0	0	0	82
Non-Energy Use	0	0	0	0	274	0	0	0	0	274
Total End Use	**2284**	**212**	**332**	**1636**	**2930**	**26**	**575**	**0**	**0**	**7996**
Own Use and Losses [e]	**204**	**13**	**8**	**138**	**219**	**0**	**0**	**0**	**0**	**582**
Conversions for Domestic Use [f]										
Electricity Generation	23	0	277	-1774	43	0	38	1057	337	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-40	0	0	40	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	0	0	0	0	1	-26	0	0	24	0
NGL Production from Reprocessing	176	-176	0	0	0	0	0	0	0	0
Total Conversions	**200**	**-225**	**277**	**-1774**	**94**	**-26**	**38**	**1057**	**361**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	59	0	554	0	87	0	0	0	836	1536
Coke Production	0	0	13	0	0	0	0	0	0	13
Steam Production	0	0	0	0	0	0	0	0	6	7
Total Conversion Losses	**59**	**0**	**567**	**0**	**87**	**0**	**0**	**0**	**836**	**1549**
Domestic Demand for Primary Energy	**2747**	**0**	**1184**	**0**	**3329**	**0**	**613**	**1057**	**1197**	**10127**
Export Demand										
Total Energy Exports	1498	268	869	151	2083	0	0	0	0	4870
Conversions for Export										
Electricity	0	0	15	-151	1	0	0	130	7	0
NGL Production Reprocessing	84	-84	0	0	0	0	0	0	0	0
Total Conversions	84	-84	15	-151	1	0	0	130	7	0
Conversion Losses-Export										
Electricity Generation	0	0	63	0	3	0	0	0	34	100
Export Demand for Primary Energy [g]	**1582**	**184**	**947**	**0**	**2087**	**0**	**0**	**130**	**40**	**4970**
Total Primary Demand [h]	**4330**	**184**	**2131**	**0**	**5416**	**0**	**613**	**1186**	**1238**	**15098**
Primary Domestic Production	**4330**	**183**	**1702**	**0**	**4094**	**0**	**613**	**1186**	**1238**	**13346**
Primary Energy Imports [h]	**0**	**0**	**429**	**0**	**1389**	**0**	**0**	**0**	**0**	**1818**
Total Primary Supply [i]	**4330**	**183**	**2131**	**0**	**5483**	**0**	**613**	**1186**	**1238**	**15164**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
					1995 Low Case					
Domestic Demand										
End Use										
Residential	589	33	3	530	216	0	124	0	0	1495
Commercial	453	16	0	373	95	0	3	0	0	941
Petrochemical	174	169	0	0	184	0	0	0	0	526
Industrial	960	15	324	741	337	21	459	0	0	2857
Transportation	7	21	0	5	1907	0	0	0	0	1940
Road	7	21	0	5	1539	0	0	0	0	1572
Rail	0	0	0	0	94	0	0	0	0	94
Air	0	0	0	0	185	0	0	0	0	185
Marine	0	0	0	0	89	0	0	0	0	89
Non-Energy Use	0	0	0	0	287	0	0	0	0	287
Total End Use	**2183**	**254**	**328**	**1648**	**3026**	**21**	**585**	**0**	**0**	**8046**
Own Use and Losses [e]	**202**	**13**	**9**	**140**	**223**	**0**	**0**	**0**	**0**	**587**
Conversions for Domestic Use [f]										
Electricity Generation	28	0	238	-1788	31	0	47	1086	358	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-40	0	0	40	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	0	0	0	0	1	-21	0	0	20	0
NGL Production from Reprocessing	218	-218	0	0	0	0	0	0	0	0
Total Conversions	**247**	**-267**	**238**	**-1788**	**81**	**-21**	**47**	**1086**	**378**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	75	0	501	0	66	0	0	0	931	1574
Coke Production	0	0	13	0	0	0	0	0	0	13
Steam Production	0	0	0	0	0	0	0	0	5	5
Total Conversion Losses	**75**	**0**	**514**	**0**	**66**	**0**	**0**	**0**	**931**	**1587**
Domestic Demand for Primary Energy	**2708**	**0**	**1089**	**0**	**3397**	**0**	**632**	**1086**	**1309**	**10220**
Export Demand										
Total Energy Exports	1498	276	853	154	1207	0	0	0	0	3988
Conversions for Export										
Electricity	0	0	26	-154	1	0	0	114	13	0
NGL Production Reprocessing	38	-38	0	0	0	0	0	0	0	0
Total Conversions	38	-38	26	-154	1	0	0	114	13	0
Conversion Losses-Export										
Electricity Generation	0	0	50	0	3	0	0	0	32	85
Export Demand for Primary Energy [g]	**1536**	**238**	**929**	**0**	**1211**	**0**	**0**	**114**	**45**	**4074**
Total Primary Demand [h]	**4244**	**238**	**2018**	**0**	**4608**	**0**	**632**	**1200**	**1354**	**14294**
Primary Domestic Production	**4254**	**239**	**1613**	**0**	**3142**	**0**	**632**	**1200**	**1354**	**12434**
Primary Energy Imports [h]	**0**	**0**	**406**	**0**	**1853**	**0**	**0**	**0**	**0**	**2259**
Total Primary Supply [i]	**4254**	**239**	**2018**	**0**	**4995**	**0**	**632**	**1200**	**1354**	**14693**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules) 1995 High Case

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	604	33	3	524	194	0	122	0	0	1480
Commercial	474	17	0	379	83	0	3	0	0	957
Petrochemical	174	169	0	0	184	0	0	0	0	526
Industrial	1271	18	398	835	332	23	465	0	0	3342
Transportation	9	25	0	5	1912	0	0	0	0	1952
Road	9	25	0	5	1542	0	0	0	0	1581
Rail	0	0	0	0	94	0	0	0	0	94
Air	0	0	0	0	193	0	0	0	0	193
Marine	0	0	0	0	83	0	0	0	0	83
Non-Energy Use	0	0	0	0	292	0	0	0	0	292
Total End Use	**2531**	**262**	**401**	**1745**	**2996**	**24**	**590**	**0**	**0**	**8548**
Own Use and Losses [e]	**219**	**14**	**10**	**146**	**225**	**0**	**0**	**0**	**0**	**613**
Conversions for Domestic Use [f]										
Electricity Generation	35	0	282	-1890	53	0	47	1112	361	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-40	0	0	40	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	0	0	0	0	2	-24	0	0	22	0
NGL Production from Reprocessing	227	-227	0	0	0	0	0	0	0	0
Total Conversions	**262**	**-276**	**282**	**-1890**	**104**	**-24**	**47**	**1112**	**383**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	92	0	590	0	95	0	0	0	939	1717
Coke Production	0	0	15	0	0	0	0	0	0	15
Steam Production	0	0	0	0	0	0	0	0	5	6
Total Conversion Losses	**92**	**0**	**605**	**0**	**95**	**0**	**0**	**0**	**939**	**1731**
Domestic Demand for Primary Energy	**3104**	**0**	**1298**	**0**	**3420**	**0**	**636**	**1112**	**1322**	**10893**
Export Demand										
Total Energy Exports	1498	265	905	140	2137	0	0	0	0	4946
Conversions for Export										
Electricity	0	0	28	-140	1	0	0	100	10	0
NGL Production Reprocessing	53	-53	0	0	0	0	0	0	0	0
Total Conversions	53	-53	28	-140	1	0	0	100	10	0
Conversion Losses-Export										
Electricity Generation	0	0	58	0	3	0	0	0	24	84
Export Demand for Primary Energy [g]	**1552**	**212**	**991**	**0**	**2141**	**0**	**0**	**100**	**34**	**5030**
Total Primary Demand [h]	**4656**	**212**	**2289**	**0**	**5561**	**0**	**636**	**1212**	**1356**	**15922**
Primary Domestic Production	**4655**	**213**	**1831**	**0**	**4361**	**0**	**636**	**1212**	**1356**	**14265**
Primary Energy Imports [h]	**0**	**0**	**458**	**0**	**1322**	**0**	**0**	**0**	**0**	**1779**
Total Primary Supply [i]	**4655**	**213**	**2289**	**0**	**5683**	**0**	**636**	**1212**	**1356**	**16044**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	2000 Low Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	619	33	3	551	205	0	133	0	0	1546
Commercial	480	16	0	393	95	0	3	0	0	988
Petrochemical	181	172	0	0	200	0	0	0	0	553
Industrial	1080	15	362	817	340	25	473	0	0	3112
Transportation	10	22	0	6	1984	0	0	0	0	2023
Road	10	22	0	6	1609	0	0	0	0	1648
Rail	0	0	0	0	97	0	0	0	0	97
Air	0	0	0	0	188	0	0	0	0	188
Marine	0	0	0	0	89	0	0	0	0	89
Non-Energy Use	0	0	0	0	314	0	0	0	0	314
Total End Use	**2371**	**259**	**365**	**1768**	**3139**	**25**	**609**	**0**	**0**	**8536**
Own Use and Losses [e]	**213**	**14**	**9**	**153**	**233**	**0**	**0**	**0**	**0**	**622**
Conversions for Domestic Use [f]										
Electricity Generation	27	0	308	-1921	43	0	61	1133	348	0
Refinery Propane Production	0	-39	0	0	39	0	0	0	0	0
Refinery Butanes Production	0	-40	0	0	40	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	0	0	0	0	1	-25	0	0	23	0
NGL Production from Reprocessing	225	-225	0	0	0	0	0	0	0	0
Total Conversions	**252**	**-273**	**308**	**-1921**	**93**	**-25**	**61**	**1133**	**372**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	67	0	542	0	86	0	0	0	906	1601
Coke Production	0	0	15	0	0	0	0	0	0	15
Steam Production	0	0	0	0	0	0	0	0	6	6
Total Conversion Losses	**67**	**0**	**557**	**0**	**86**	**0**	**0**	**0**	**906**	**1616**
Domestic Demand for Primary Energy	**2903**	**0**	**1239**	**0**	**3551**	**0**	**670**	**1133**	**1278**	**10774**
Export Demand										
Total Energy Exports	1498	267	878	173	1052	0	0	0	0	3868
Conversions for Export										
Electricity	0	0	34	-173	2	0	0	132	5	0
NGL Production Reprocessing	44	-44	0	0	0	0	0	0	0	0
Total Conversions	44	-44	34	-173	2	0	0	132	5	0
Conversion Losses-Export										
Electricity Generation	0	0	94	0	2	0	0	0	10	107
Export Demand for Primary Energy [g]	**1543**	**223**	**1006**	**0**	**1056**	**0**	**0**	**132**	**15**	**3975**
Total Primary Demand [h]	**4446**	**223**	**2245**	**0**	**4607**	**0**	**670**	**1266**	**1293**	**14750**
Primary Domestic Production	**4472**	**223**	**1738**	**0**	**2889**	**0**	**670**	**1266**	**1293**	**12550**
Primary Energy Imports [h]	**0**	**0**	**507**	**0**	**1935**	**0**	**0**	**0**	**0**	**2442**
Total Primary Supply [l]	**4472**	**223**	**2245**	**0**	**4824**	**0**	**670**	**1266**	**1293**	**14992**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	2000 High Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	634	33	3	545	172	0	130	0	0	1517
Commercial	499	17	0	407	79	0	5	0	0	1007
Petrochemical	181	172	0	0	200	0	0	0	0	553
Industrial	1385	19	545	962	349	28	483	0	0	3770
Transportation	14	30	0	7	2018	0	0	0	0	2068
Road	14	30	0	7	1636	0	0	0	0	1686
Rail	0	0	0	0	100	0	0	0	0	100
Air	0	0	0	0	198	0	0	0	0	198
Marine	0	0	0	0	85	0	0	0	0	85
Non-Energy Use	0	0	0	0	325	0	0	0	0	325
Total End Use	**2713**	**270**	**548**	**1920**	**3144**	**29**	**617**	**0**	**0**	**9241**
Own Use and Losses [e]	**231**	**15**	**10**	**159**	**238**	**0**	**0**	**0**	**0**	**653**
Conversions for Domestic Use [f]										
Electricity Generation	37	0	359	-2079	67	0	61	1197	358	0
Refinery Propane Production	0	-40	0	0	40	0	0	0	0	0
Refinery Butanes Production	0	-41	0	0	41	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	0	0	0	0	2	-29	0	0	27	0
NGL Production from Reprocessing	235	-235	0	0	0	0	0	0	0	0
Total Conversions	**273**	**-285**	**359**	**-2079**	**118**	**-29**	**61**	**1197**	**384**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	91	0	707	0	106	0	0	0	903	1806
Coke Production	0	0	17	0	0	0	0	0	0	17
Steam Production	0	0	0	0	0	0	0	0	7	7
Total Conversion Losses	**91**	**0**	**724**	**0**	**106**	**0**	**0**	**0**	**903**	**1823**
Domestic Demand for Primary Energy	**3308**	**0**	**1642**	**0**	**3606**	**0**	**677**	**1197**	**1287**	**11717**
Export Demand										
Total Energy Exports	1498	259	972	151	2222	0	0	0	0	5102
Conversions for Export										
Electricity	0	0	18	-151	1	0	0	128	2	0
NGL Production Reprocessing	58	-58	0	0	0	0	0	0	0	0
Total Conversions	58	-58	18	-151	1	0	0	128	2	0
Conversion Losses-Export										
Electricity Generation	0	0	37	0	3	0	0	0	6	46
Export Demand for Primary Energy [g]	**1556**	**201**	**1028**	**0**	**2226**	**0**	**0**	**128**	**9**	**5148**
Total Primary Demand [h]	**4864**	**201**	**2670**	**0**	**5831**	**0**	**677**	**1326**	**1296**	**16865**
Primary Domestic Production	**4863**	**202**	**2110**	**0**	**4644**	**0**	**677**	**1326**	**1296**	**15118**
Primary Energy Imports [h]	**0**	**0**	**559**	**0**	**1308**	**0**	**0**	**0**	**0**	**1867**
Total Primary Supply [I]	**4863**	**202**	**2670**	**0**	**5952**	**0**	**677**	**1326**	**1296**	**16986**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	2005 Low Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	641	34	3	577	195	0	139	0	0	1588
Commercial	506	17	0	415	90	0	4	0	0	1031
Petrochemical	181	174	0	0	219	0	0	0	0	574
Industrial	1209	15	401	903	326	28	482	0	0	3366
Transportation	14	25	0	8	2072	0	0	0	0	2118
Road	14	25	0	8	1684	0	0	0	0	1730
Rail	0	0	0	0	102	0	0	0	0	102
Air	0	0	0	0	192	0	0	0	0	192
Marine	0	0	0	0	94	0	0	0	0	94
Non-Energy Use	0	0	0	0	340	0	0	0	0	340
Total End Use	**2550**	**266**	**404**	**1902**	**3241**	**29**	**625**	**0**	**0**	**9018**
Own Use and Losses [e]	**225**	**15**	**9**	**158**	**241**	**0**	**0**	**0**	**0**	**647**
Conversions for Domestic Use [f]										
Electricity Generation	40	0	351	-2060	46	0	66	1215	343	0
Refinery Propane Production	0	-40	0	0	40	0	0	0	0	0
Refinery Butanes Production	0	-40	0	0	40	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	0	0	0	0	1	-29	0	0	27	0
NGL Production from Reprocessing	232	-232	0	0	0	0	0	0	0	0
Total Conversions	**272**	**-281**	**351**	**-2060**	**96**	**-29**	**66**	**1215**	**370**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	98	0	688	0	87	0	0	0	870	1743
Coke Production	0	0	17	0	0	0	0	0	0	17
Steam Production	0	0	0	0	0	0	0	0	7	7
Total Conversion Losses	**98**	**0**	**705**	**0**	**87**	**0**	**0**	**0**	**870**	**1760**
Domestic Demand for Primary Energy	**3145**	**0**	**1470**	**0**	**3665**	**0**	**691**	**1215**	**1240**	**11425**
Export Demand										
Total Energy Exports	1498	260	905	163	1122	0	0	0	0	3949
Conversions for Export										
Electricity	0	0	16	-163	1	0	0	145	1	0
NGL Production Reprocessing	49	-49	0	0	0	0	0	0	0	0
Total Conversions	49	-49	16	-163	1	0	0	145	1	0
Conversion Losses-Export										
Electricity Generation	0	0	32	0	3	0	0	0	3	38
Export Demand for Primary Energy [g]	**1548**	**211**	**953**	**0**	**1126**	**0**	**0**	**145**	**4**	**3987**
Total Primary Demand [h]	**4692**	**211**	**2423**	**0**	**4791**	**0**	**691**	**1360**	**1244**	**15411**
Primary Domestic Production	**4677**	**211**	**1837**	**0**	**2772**	**0**	**691**	**1360**	**1244**	**12792**
Primary Energy Imports [h]	**0**	**0**	**585**	**0**	**2266**	**0**	**0**	**0**	**0**	**2851**
Total Primary Supply [i]	**4677**	**211**	**2423**	**0**	**5038**	**0**	**691**	**1360**	**1244**	**15643**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules)	2005 High Case									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	641	34	3	572	164	0	134	0	0	1548
Commercial	519	18	0	445	81	0	5	0	0	1068
Petrochemical	181	174	0	0	219	0	0	0	0	574
Industrial	1487	19	632	1093	372	34	496	0	0	4134
Transportation	18	34	0	9	2138	0	0	0	0	2198
Road	18	34	0	9	1731	0	0	0	0	1791
Rail	0	0	0	0	107	0	0	0	0	107
Air	0	0	0	0	208	0	0	0	0	208
Marine	0	0	0	0	91	0	0	0	0	91
Non-Energy Use	0	0	0	0	354	0	0	0	0	354
Total End Use	**2846**	**279**	**636**	**2119**	**3328**	**34**	**635**	**0**	**0**	**9876**
Own Use and Losses [e]	**241**	**16**	**11**	**177**	**248**	**0**	**0**	**0**	**0**	**693**
Conversions for Domestic Use [f]										
Electricity Generation	42	0	415	-2296	42	0	66	1342	389	0
Refinery Propane Production	0	-40	0	0	40	0	0	0	0	0
Refinery Butanes Production	0	-41	0	0	41	0	0	0	0	0
Butane used in Refineries	0	32	0	0	-32	0	0	0	0	0
Steam Production	0	0	0	0	2	-34	0	0	32	0
NGL Production from Reprocessing	246	-246	0	0	0	0	0	0	0	0
Total Conversions	**288**	**-295**	**415**	**-2296**	**93**	**-34**	**66**	**1342**	**422**	**0**
Conversion Losses-Domestic [f]										
Electricity Generation	102	0	827	0	84	0	0	0	976	1989
Coke Production	0	0	20	0	0	0	0	0	0	20
Steam Production	0	0	0	0	0	0	0	0	8	9
Total Conversion Losses	**102**	**0**	**846**	**0**	**84**	**0**	**0**	**0**	**976**	**2009**
Domestic Demand for Primary Energy	**3477**	**0**	**1908**	**0**	**3753**	**0**	**701**	**1342**	**1398**	**12578**
Export Demand										
Total Energy Exports	1498	267	1054	172	2151	0	0	0	0	5143
Conversions for Export										
Electricity	0	0	16	-172	0	0	0	153	2	-1
NGL Production Reprocessing	57	-57	0	0	0	0	0	0	0	0
Total Conversions	57	-57	16	-172	0	0	0	153	2	-1
Conversion Losses-Export Electricity Generation	0	0	34	0	4	0	0	0	5	43
Export Demand for Primary Energy [g]	**1556**	**210**	**1104**	**0**	**2155**	**0**	**0**	**153**	**7**	**5185**
Total Primary Demand [h]	**5032**	**210**	**3012**	**0**	**5908**	**0**	**701**	**1495**	**1404**	**17763**
Primary Domestic Production	**5031**	**210**	**2374**	**0**	**4601**	**0**	**701**	**1495**	**1404**	**15817**
Primary Energy Imports [h]	**0**	**0**	**638**	**0**	**1409**	**0**	**0**	**0**	**0**	**2046**
Total Primary Supply [i]	**5031**	**210**	**3012**	**0**	**6010**	**0**	**701**	**1495**	**1404**	**17863**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Appendix 11
Contact Persons for Inquiries About This Report

Technical questions on this report should be directed to the following members of the Project Working Group for the matters indicated:

Demand for all forms of energy	Elizabeth Ruddick	(613) 998-7936
Exports of natural gas	Cas Szuber	(613) 990-6331
Exports and imports of oil and refined petroleum products	Nobby Monteiro	(613) 990-6241
Supply and exports of electricity	Pierre Pinault	(613) 990-0321
Supply of oil, natural gas, NGL and coal	Bob Lomas	(613) 998-7918

General questions on this report should be directed to:

	Ian Melzer	(613) 998-7931

Canada

National Energy Board

CANADIAN ENERGY

Supply and Demand 1987-2005

SUMMARY

September 1988

CANADIAN ENERGY
SUPPLY AND DEMAND 1987-2005

Summary

NATIONAL ENERGY BOARD
SEPTEMBER, 1988

Cat. No. NE23-15/1988-1E
ISBN 0-662-16496-2

This report is published separately in both official languages.

Ce rapport est publié séparément dans les deux langues officielles.

Copies are available on request from:

Regulatory Support Office
National Energy Board
473 Albert Street
Ottawa, Canada
K1A 0E5
(613) 998-7204

Exemplaires disponibles auprès du:

Bureau du soutien de la réglementation
Office national de l'énergie
473, rue Albert
Ottawa (Canada)
K1A 0E5
(613) 998-7204

Printed in Canada

Imprimé au Canada

TABLE OF CONTENTS

Energy supply and demand can be measured in many different units. We convert these, for purposes of comparison, to multiples of joules. In particular, we refer to gigajoules (a thousand million joules) - about the energy contained in 30 litres of gasoline, the petajoule (a million gigajoules) - about the energy used for all purposes in Toronto or Montreal about every 17 hours, and the exajoule (a thousand petajoules). A table of key conversion factors, terms and abbreviations appears on page 22.

Foreword

The **National Energy Board** was created by an Act of Parliament in 1959. It has two principal responsibilities under the *National Energy Board Act:*

- to regulate specific matters concerning oil, natural gas and electricity in the public interest - these include:
  - authorizing exports of oil, natural gas and electricity,
  - authorizing construction of international and interprovincial pipelines and international power lines,
  - setting just and reasonable tolls for pipelines under federal jurisdiction;
- to advise the Government on the development and use of energy resources.

The Act also requires the Board to keep under review the outlook for Canadian supply of all major energy commodities and their by-products and the demand for Canadian energy in Canada and abroad.

This Summary Report is a companion volume to a detailed report which sets out the energy demand, supply and price projections prepared by National Energy Board staff over the course of January to September 1988.

This is a staff report which the Board publishes about every second year, the previous one being *Canadian Energy Supply and Demand 1985-2005,* October, 1986. This work is separate and distinct from any of the Board's regulatory proceedings; all estimates in this report are independent of and without prejudice to Board consideration of future energy export or facilities applications.

Our thanks to all those who provided their time and expertise to this endeavour:

- to those who consulted with us on our preliminary assumptions and results,
- to those who provided information, and
- to the many members of Board staff who contributed.

Copies of this report, the detailed report, or previous reports are available by contacting the Board at the address or telephone number provided on the back of the title page.

Introduction

When we prepared our previous report *Canadian Energy Supply and Demand 1985-2005* (the October 1986 Report), world energy markets were characterized by excess supply and oil and natural gas prices had fallen dramatically. Although the situation of oversupply and low prices has continued to the present time, there have been major changes in North American natural gas markets and a number of electric utilities are pursuing an expanded range of supply options and demand management programs.

Our general approach is similar to that in our 1986 report insofar as we define lower and higher sustainable paths of oil prices. There are, however, major innovations in this report:

- we have taken a broader view of the relationship between economic growth and oil prices;
- we allow natural gas prices to change as required in order to avoid natural gas supply and demand crossovers;
- we do projections of natural gas exports over the long term which extend beyond the expiry of existing licences;
- we examine an alternative electricity supply option which involves higher levels of interprovincial trade in eastern Canada and increased exports compared with those contained in our low and high case projections.

World Economic Growth and Oil Price Scenarios

Our approach is based on the assumption that, given the present state of the world oil market, characterized as it is by substantial excess supply, the extent to which oil prices can increase on a sustained basis depends largely upon how much international demand grows, and consequently what effect this demand growth has on the cost of non-OPEC oil supply.

We adopt two scenarios for world economic growth - a high scenario with average annual growth of about three percent and a low scenario with growth of only two percent. In this framework, Canadian economic growth will be influenced more by the world economic environment in general, of which world oil prices are a part, than by the level of oil prices alone.

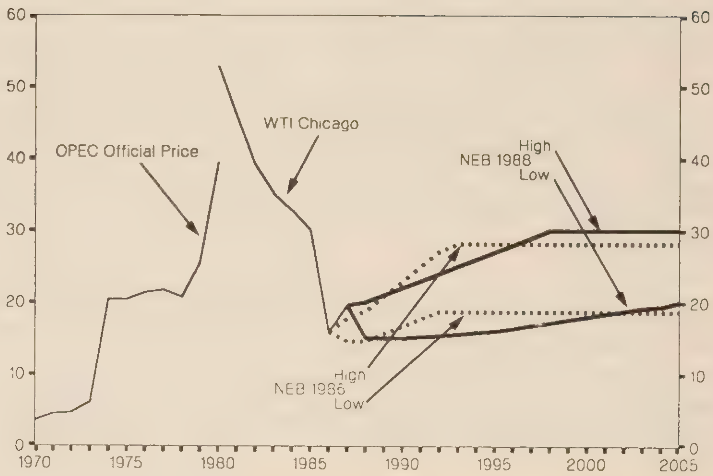
For each economic growth scenario we constructed a world oil price scenario. Higher demand for oil results primarily from higher economic growth and lower oil demand from lower growth. Thus high economic growth and high oil demand, resulting in high oil prices, constitute one scenario (our high case); and lower economic growth along with lower oil demand, resulting in lower oil prices, constitutes the other scenario (our low case). We take into account that high prices discourage demand and low prices encourage it; however, barring very large price surges (as occurred between 1979 and 1981) we anticipate that economic growth will influence oil demand more than will the crude oil price.

The definition of the lower and higher oil price paths does not mean that oil prices will remain on either one of these paths year after year. The oil price will most likely fluctuate above or below each of these paths in any year, but it is not possible to forecast these fluctuations. The meaning of these two scenarios is that each is a qualitatively different, long-term view emerging from different behavioural assumptions sustaining either relatively lower or higher prices. Moreover, it is possible that the actual path could be a composite of the two projections, for example close to the low path in the earlier years, drifting up over time toward the higher path by the end of the study period.

Our energy supply and demand scenarios are not forecasts of what will happen. Each scenario is an alternative view of what we would expect under different sustainable outlooks for economic growth and world oil prices. All of the results of our analysis critically depend on the underlying assumptions we have used throughout the report. Different assumptions would produce results different from those reported here.

Figure 1
World Oil Prices

($US 1987/BBL)



Canadian Economic Growth

We use our estimates of world economic growth and world oil prices to obtain projections of economic growth for Canada. The high case has real gross domestic product growing on average at 2.9 percent annually from 1986 to 2005; the low case features annual economic growth of 2.2 percent. As for oil prices, we do not attempt to project any cyclical pattern of Canadian economic performance. These growth rates should be regarded as long-term, sustainable trends, around which annual growth rates will fluctuate.

In both cases growth is concentrated more in the goods-producing industries than it has been in recent years. In the high case, world demand for our exports is relatively strong; therefore, growth is relatively stronger in durables manufacturing and energy intensive industries (such as pulp, paper, iron and steel) where Canada has comparative advantage in international trade. In the low case, export demand is lower as is the contribution of export industries to gross domestic product.

The composition of economic growth influences energy demand insofar as the industrial (goods-producing) sector uses four to five times as much energy per dollar of output as the commercial (services-producing) sector. Moreover, some goods-producing industries use energy in their production processes much more intensively than others.

Table 1

Canadian Economic Activity

Average Annual Growth Rates (Percent)

	1986-2005	
	Low	High
Real Gross Domestic Product	2.2	2.9
Real Personal Disposable Income	1.7	2.3
Households	1.3	1.3
Car Stock	1.8	2.0

Table 2

Output by Sector (1971 dollars)

Average Annual Growth Rates (Percent)

	1986-1990		1990-2005		1986-2005	
	Low	High	Low	High	Low	High
Industrial	1.9	3.5	2.6	3.5	2.5	3.5
Forestry	1.8	2.1	2.1	2.5	2.0	2.4
Mining	0.6	2.8	1.5	2.4	1.3	2.5
Manufacturing	2.1	3.7	2.7	3.8	2.6	3.8
Construction	1.5	3.0	2.8	3.0	2.5	3.0
Energy - intensive[a]	1.8	3.6	2.1	3.2	2.1	3.3
Commercial	2.5	2.8	1.8	2.4	2.0	2.5
Total Gross Domestic Product	**2.3**	**3.1**	**2.0**	**2.9**	**2.2**	**2.9**

Note: [a] Mining, smelting and refining, iron and steel, pulp and paper, chemicals, cement and petroleum refining.

Natural Gas Prices

At the time we drafted the 1986 report, Canada was at the early stage of transition from regulated gas prices to a more competitive market structure. Because it was not yet clear how natural gas prices in Canada would be determined, we assumed that the price of natural gas would be linked to the price of heavy fuel oil. The results of our analysis showed the problem of assuming a fixed link between natural gas and oil prices. Natural gas supply and demand projected in that report were never balanced: when the gas price exceeded supply cost (until the late 1990s) excess gas supply persisted; thereafter, when the cost of gas reserves additions exceeded the price, supply became insufficient to meet demand and a supply/demand crossover occurred (see Figure 2, Panel 1). We acknowledged that this could not persist and that further adjustment was necessary.

In this report we allow natural gas prices to change, reflecting supply and demand conditions in the gas market. The price of oil affects natural gas prices because the two are substitutable in many uses. But the gas prices required to maintain gas supply/demand balance may rise or fall relative to oil prices (see Figure 2, Panel 2).

At the outset of the study period there is excess gas supply exerting downward pressure on gas prices. However, later on, exploration and development costs increase as our natural gas resources are progressively depleted, meaning that natural gas prices will have to increase in order to meet the cost of finding and producing needed future supplies.

We project that natural gas fieldgate prices will increase in real

Figure 2

Natural Gas Market

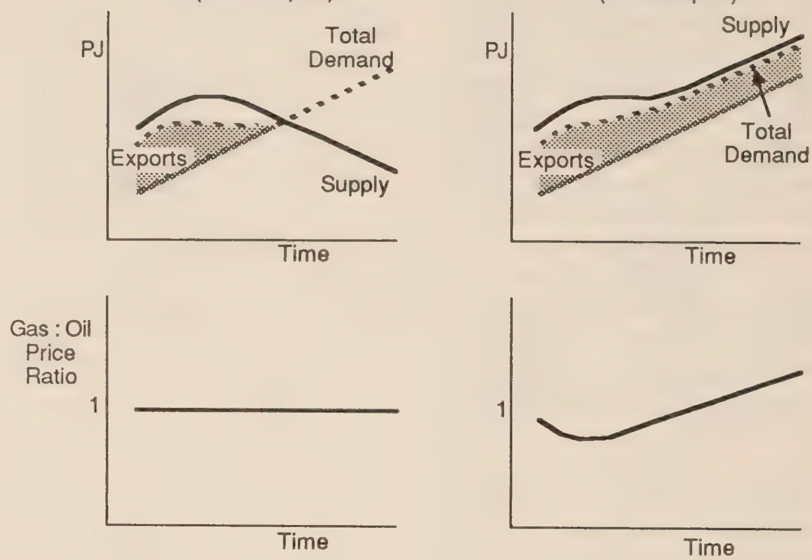
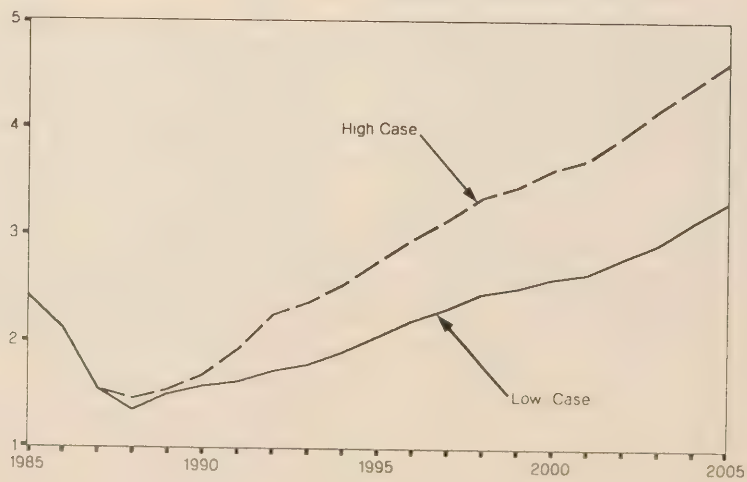


Figure 3

Fieldgate Natural Gas Prices Low and High Cases

($C 1987/GJ)



terms over the study period. In the low case the average price increases from about $1.55 per gigajoule in 1987 to some $3.30 in 2005. In the high case it rises more quickly, and to a higher level, about $4.70 in 2005.

In today's gas market, different prices (net of transportation and distribution costs) are charged to different customers. This is frequently referred to as "price streaming". To construct our end use price projections we had to make assumptions about the future of this practice.

In the high case, end use gas prices for the industrial, commercial and residential sectors were projected so as to eliminate streaming by 1991. In this case, gas prices do not exceed oil prices until near the end of the study period when gas becomes more expensive than heavy fuel oil in eastern Canadian industrial markets.

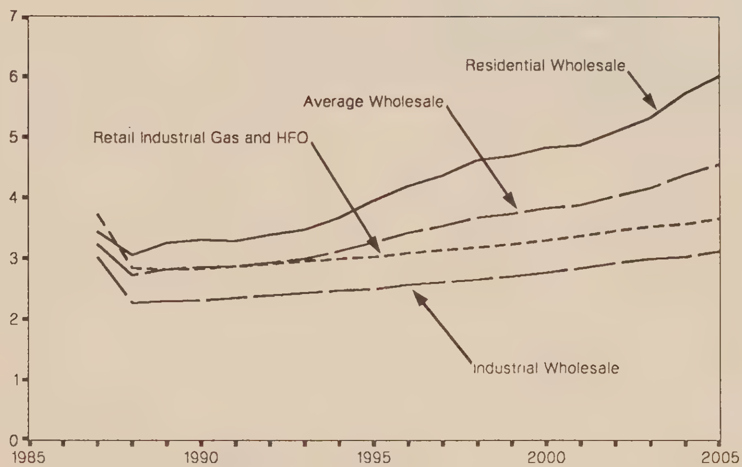
The low case presents serious difficulties for the pricing of natural gas because the oil price is very low relative to the incremental cost of supplying gas. We decided to maintain streaming in this case. Had we eliminated streaming, we estimate that, by the end of the study period, the Canadian gas market would be about 25 percent (615 petajoules) smaller and the higher transmission and distribution costs to remaining users would result in gas prices close to those paid if streaming were to occur.

In the low case, we assumed lower Canadian energy supply costs than in the high case, on the basis that when energy prices are low, costs of exploration, drilling and production tend to be lower than they are when prices are high.

Figure 4

Natural Gas Pricing - Ontario Low Case

($C 1987/GJ)



Electricity Prices

We estimated electricity prices in both cases by taking into account any price changes announced by utilities for the short term and by assuming constant real prices thereafter. In order to verify whether this assumption was reasonable, we estimated the prices necessary to satisfy utilities' revenue requirements. We found that, generally, constant real prices are higher than needed to meet utilities' revenue requirements. However, following consultations with the industry, we decided to continue to assume that electricity prices will increase with the general rate of inflation. The main factors influencing this judgement are that real price reductions would not be consistent with the demand management and higher internal cash generation objectives which some utilities wish to pursue.

Table 3

Electricity Price Growth

1987-2005

Average Annual Growth Rates (Percent)

	Low Case		High Case	
	Inflation[a]	Revenue Requirements[b]	Inflation[a]	Revenue Requirements[b]
Atlantic	4.2	3.3	4.7	4.6
Quebec	4.3	3.2	4.8	4.3
Ontario	4.4	2.0	4.8	2.5
Manitoba	4.3	3.6	4.8	3.2
Saskatchewan	4.4	1.6	4.9	2.1
Alberta	4.4	3.3	4.8	3.9
British Columbia	4.4	1.5	4.8	3.2

Notes: [a] Announced price increases after which price growth tracks inflation.
[b] Announced price increases after which price growth is calculated to meet current stated financial objectives and corresponding revenue requirements.

Energy Demand

End use energy demand grows at 1.4 percent annually in the low case and 1.8 percent in the high from 1986 to 2005. In 2005, end use demand in the high case is nine percent greater than that of the low case, as the positive impact of higher economic activity more than offsets the negative impact of higher oil prices.

We expect fuel shares to remain relatively stable through 2005. The major exceptions are:

- the oil share which decreases in both cases, reflecting continued, slow, switching away from oil, and
- coal's share which, although small, doubles over the projection period in the high case, reflecting our assumption that in this case some coal will be used to generate steam for the in situ recovery of bitumen.

Shares of electricity and natural gas rise slightly. The share of renewables changes little; we do not think that the energy prices in either of our cases will be conducive to an increased market share for these energy forms.

Oil is confined increasingly to its major captive market - transportation - and although the level of end use oil demand increases slowly in both cases, by 2005 it is still lower than it was in 1976.

Our projections show continued energy conservation and improvements in energy efficiency, which contribute to average annual declines in energy intensity (end use energy demand per unit of real domestic product) of 0.7 percent and 1 percent over the period 1986 to 2005, in the low and high cases respectively. These rates of improvement are below those

Figure 5
End Use Energy Demand by Fuel Canada

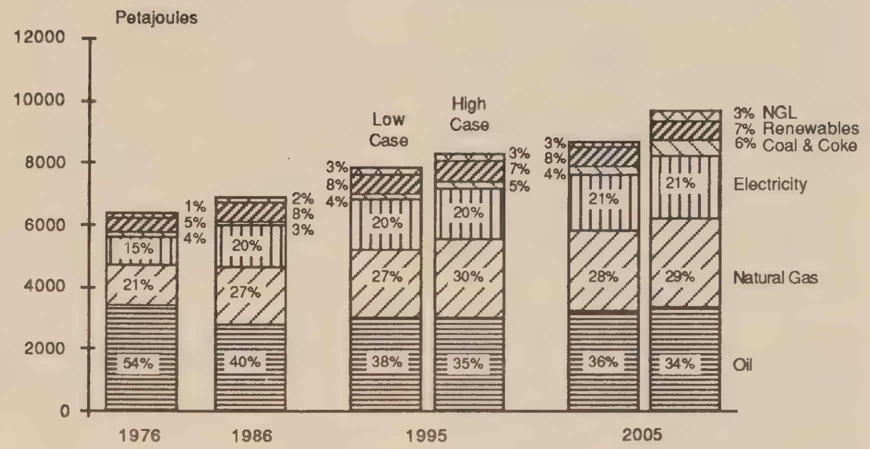
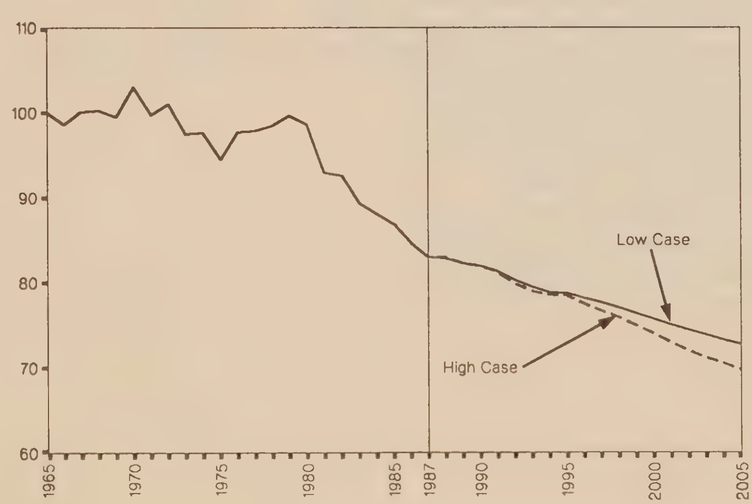


Figure 6
End Use Energy Demand per Unit of RDP

Index (1965=100)



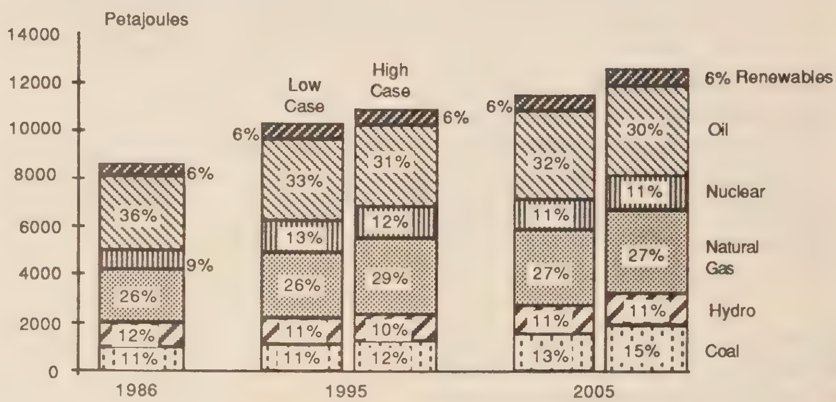
experienced over the past decade, and we believe they are well within the bounds of achievable gains using existing technologies. As a consequence energy demand grows more slowly than general economic activity. On balance, given the efficiency gains we have built into our estimates, we think there is a greater risk that energy demand may be higher than we have projected over the next two decades, rather than lower.

Primary energy demand includes end use demand and the fuel use and losses associated with the production and distribution of energy. Electricity is not shown explicitly in primary energy demand; it is replaced by an estimate of the energy sources required to generate it.

Over the outlook period total domestic demand for primary energy grows at 1.5 percent annually in the low case and 2 percent in the high, growth rates which are similar to those of end use demand (1.4 and 1.8 percent respectively). The marginally higher growth rate of primary energy demand is due to an increase in conversion losses as a result of increased thermal generation of electricity.

The fuel shares of domestic demand for primary energy are similar in the high and low cases. Over the projection period, oil's share declines (but not its absolute level), while those of nuclear, coal and natural gas increase. This reflects an increasing role for nuclear and coal generation of electricity, and increased use of natural gas.

Figure 7
Domestic Demand for Primary Energy by Fuel Canada



Energy Export Projections

In previous reports we projected **natural gas** exports not to exceed existing licence authorizations; we did not allow for any exports beyond the horizon of existing licence authorizations. In this report we have assessed the prospects for natural gas exports based on an analysis of the competitiveness of Canadian natural gas in U.S. regional markets and we have taken account of how exports affect gas supply, demand and prices in Canada.

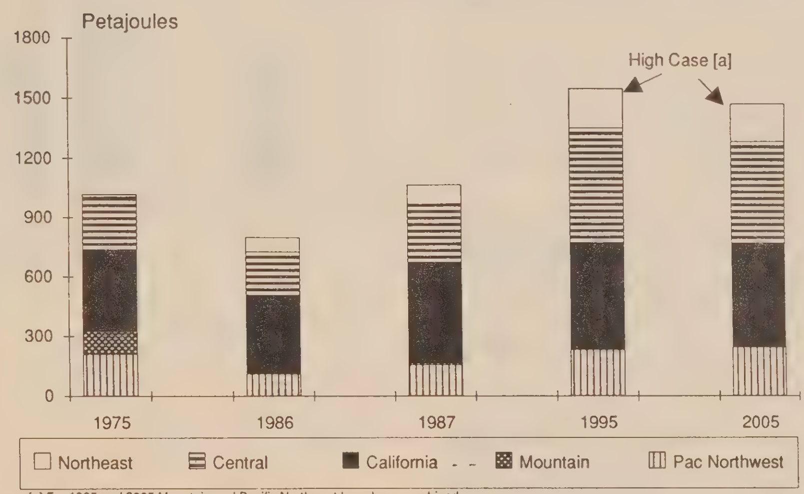
Natural gas exports grow from one exajoule in 1987 to 1.5 exajoules in 1992 in both scenarios; thereafter they are stable. The reasons for this stability are that we project very slow U.S. gas demand growth, and a competitive supply of U.S. gas sufficient to meet over 90 percent of U.S. requirements during our study period. Canada's share of the U.S. market grows from approximately 6 percent in 1987 to about 8 percent by 1992. There is virtually no difference in export volumes between the two scenarios, both in total and in terms of their regional composition. California and the central U.S. remain the largest export destinations, together accounting for over 70 percent of our exports. The northeast region is expected to take a larger percentage of our exports, 13 percent by 1992 compared with 9 percent in 1987.

Table 4
Net Energy Exports (Imports)
(Petajoules)

			Low Case		High Case	
	1975	1986	1995	2005	1995	2005
Coal	(145)	360	445	320	445	415
Electricity	10	140	155	165	140	170
Natural Gas	1040	795	1500	1500	1500	1500
NGL	145	130	275	260	265	265
Crude Oil & Products	(110)	570	(645)	(1145)	815	740
Total	**940**	**2000**	**1730**	**1100**	**3165**	**3095**

Note: The numbers on this table have been rounded to the nearest unit of five.

Figure 8
Natural Gas Exports



[a] For 1995 and 2005 Mountain and Pacific Northwest have been combined.

Firm **electricity** exports are based on building generating capacity ahead of the time needed to meet domestic requirements; interruptible exports are based on temporary surpluses such as those which occur at off-peak times. For firm electricity exports we have made the same assumptions in both the low and high cases, based on our assessment of export markets:

- a projected shortage of generating capacity in northeastern U.S. markets in the mid-1990s, combined with a high degree of competitiveness on the part of Canadian utilities;

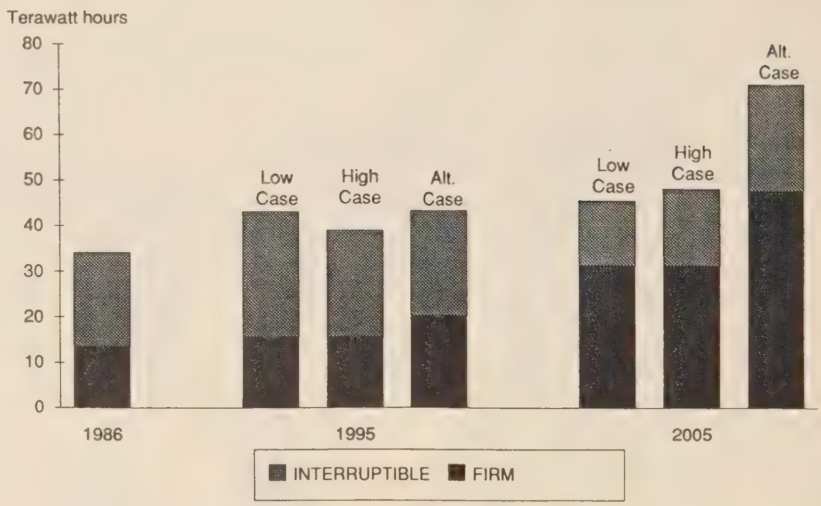
- no required capacity additions in north-central U.S. markets, combined with low cost, coal-based generation in these markets; and

- growing requirements in western states, along with competitive Canadian supplies.

In both the low and high cases total electricity exports grow slowly, but the share taken by firm exports is projected to grow rapidly, from 29 percent of total exports in 1986 to about two-thirds in 2005. In some provinces (Quebec, New Brunswick, Manitoba, and British Columbia) we expect firm export contracts to be signed which will result in the pre-building of generating plants or the dedicating of specific projects to export markets.

The potential market for electricity exports is very large. We therefore constructed an alternative scenario (in addition to our low and high cases) which includes a larger market for firm exports than in the high case. In the alternative scenario, total electricity exports in 2005 are about 50 percent greater than in the high case.

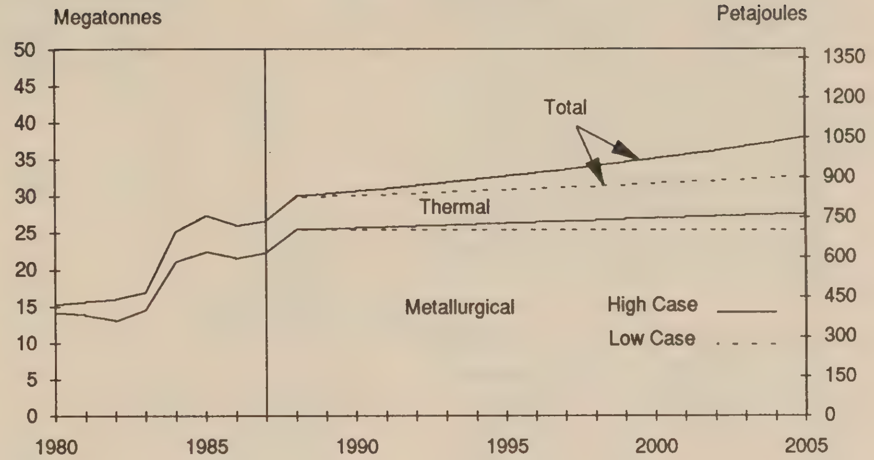
Figure 9
Net Electricity Exports by Type



Only coal and petroleum imports are large enough that there is an appreciable difference between gross and net exports. Canada exports coal and crude oil, mainly from western Canada at the same time as it imports them, mostly to eastern Canada. These trading patterns are largely the result of different transportation costs between alternative sources and destinations.

Coal imports rise in both cases mainly to satisfy electricity generation requirements in Ontario. Gross coal exports also rise. Net exports rise in both cases to 1995 and then fall over the ensuing decade, in the low case to about 10 percent below the 1986 level by 2005, and in the high case to about 15 percent above the 1986 level.

Figure 10
Coal Exports



Imports of light crude **oil** to eastern Canada increase in the low case but decrease in the high case; the difference between the two cases results more from differences in our supply projections than from demand. Imports of heavy crude oil are assumed to remain level in both cases. Product imports are expected to more than double in both cases as we assume no construction of new refineries.

Gross exports of light crude oil from western Canada continue but decline throughout the projection period in both cases, declining faster in the low case than in the high. Exports of heavy crude oil decline in the low case over time, but increase substantially in the high case. Gross exports of products are similar in the two cases.

As a result, in the low case Canada becomes a net importer of increasing quantities of light crude oil; in the high case net imports of light crude oil grow more slowly. Net exports of heavy crude oil continue throughout the outlook period in both cases, decreasing in the low case but increasing in the high. Net imports of petroleum products are similar in the two cases.

We expect **natural gas liquids** production, except for pentanes plus, to continue to exceed domestic demand by a substantial margin. Net exports of natural gas liquids increase in both cases to about double the 1986 level by 2005.

Table 5

Exports and Imports of Crude Oil and Products

(Thousands of Cubic Metres per Day)

Low Case

	1987	**1990**	**1995**	**2000**	**2005**
Exports					
Light	44	35	14	7	7
Heavy	56	61	37	34	39
Subtotal Crude Oil	100	96	51	41	46
Products	27	35	34	34	34
Total	**127**	**131**	**85**	**75**	**80**
Imports					
Light	58	69	70	80	95
Heavy	7	7	7	7	7
Subtotal Crude Oil	65	76	77	87	102
Products	23	24	38	42	50
Total	**88**	**100**	**115**	**129**	**152**
Net Crude Oil and Products Exports (Imports)	39	31	(30)	(54)	(72)

High Case

	1987	**1990**	**1995**	**2000**	**2005**
Exports					
Light	44	42	15	27	22
Heavy	56	79	105	98	98
Subtotal Crude Oil	100	121	120	125	120
Products	27	34	33	33	33
Total	127	155	153	158	153
Imports					
Light	58	69	56	44	44
Heavy	7	7	7	7	7
Subtotal Crude Oil	65	76	63	51	51
Products	23	20	31	41	50
Total	88	96	94	92	101
Net Crude Oil and Products Exports (Imports)	39	59	59	66	52

Note: The numbers in this table have been rounded.

Natural Gas Supply

Remaining established reserves of natural gas at year-end 1986 include 75.3 exajoules in conventional areas and 17.6 exajoules in frontier regions.

A total of 46 exajoules of natural gas from the conventional areas is projected to be added over the projection period in the low case and 51 exajoules in the high case. Reserves additions are higher than projected in our 1986 report because natural gas prices rise more in the current projections, we use a higher estimate of technically recoverable resources, and the costs of reserves additions are sensitive to the price environment.

As Canada develops natural gas from smaller and deeper pools in western Canada, costs are expected to increase. We estimate that ultimately about 205 exajoules of western Canadian gas would become economic at prices of $4.60 per gigajoule in the low case and $6.40 per gigajoule in the high. (This is about 20 exajoules higher than the ultimate economic potential for conventional areas used in the 1986 report.) The lower gas costs in the low case occur because we have assumed reduced finding and production costs in this case.

In both the low and high cases we expect natural gas supply and demand to come into rough balance in the early to mid-1990s. This balance is then maintained throughout the rest of the period but at considerably higher prices, reflecting increasing supply costs. The main differences between the cases are that in the high case prices rise more quickly and to a higher level. In both cases, we project Mackenzie Delta gas production beginning in 1999; in the high case, we also include Venture gas production commencing in 2004.

Figure 11

Reserves of Marketable Natural Gas

Exajoules

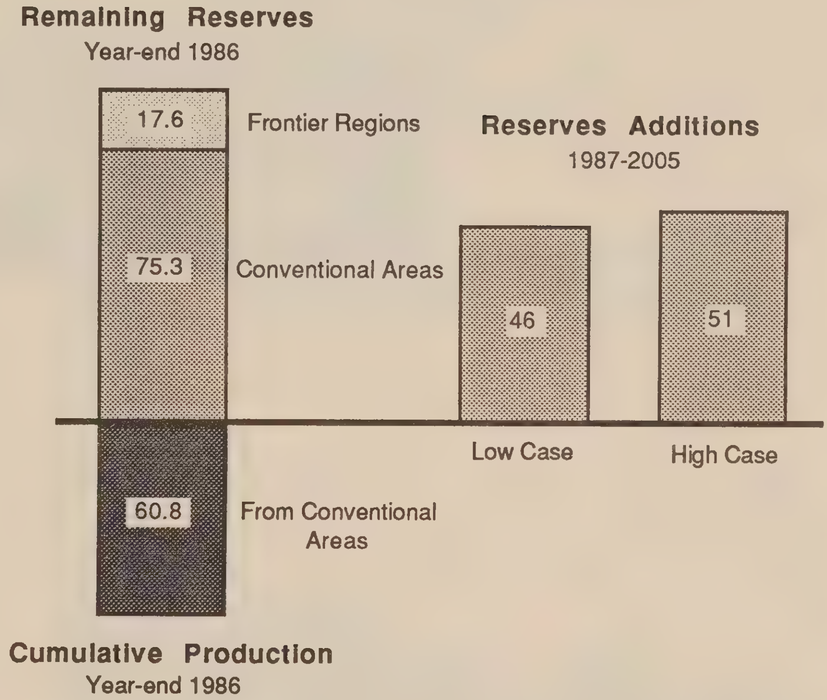
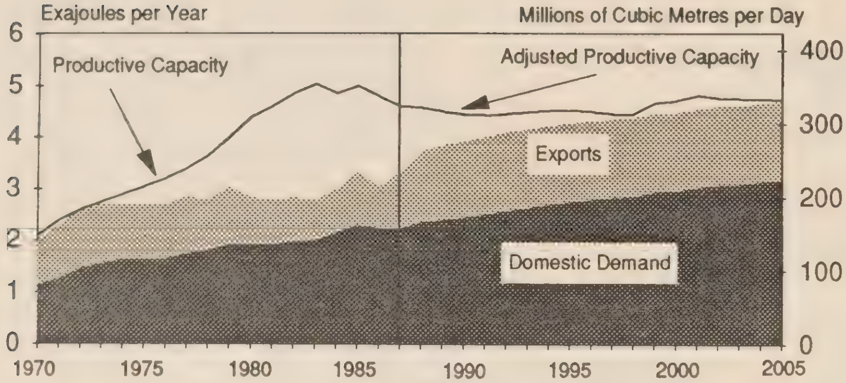


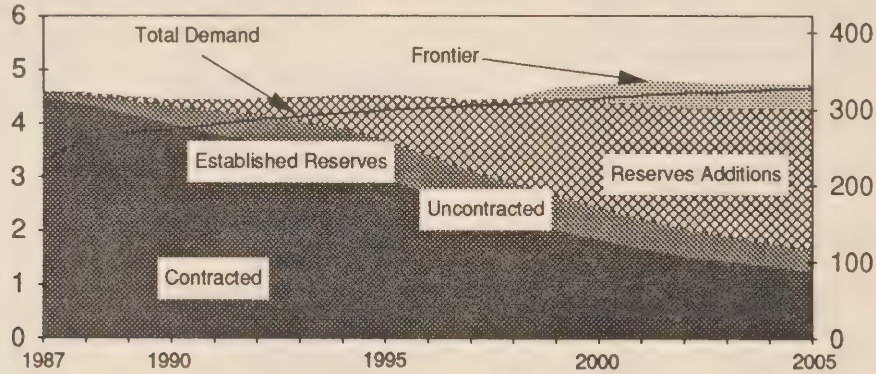
Figure 12

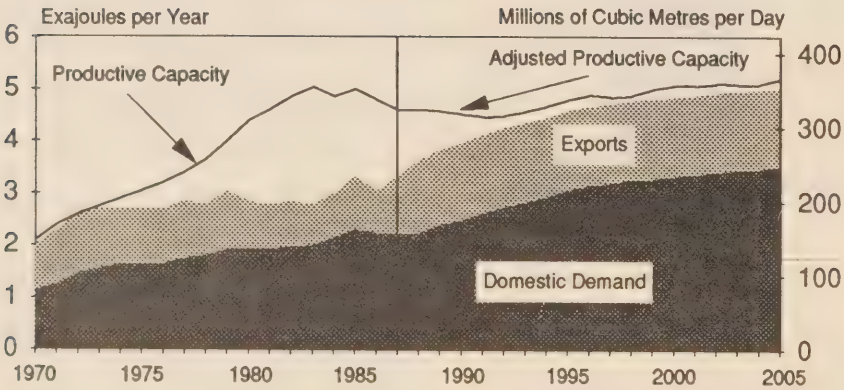
Natural Gas Supply and Demand

Note: Supply represents productive capacity adjusted to reflect that quantities produced equal total primary demand.

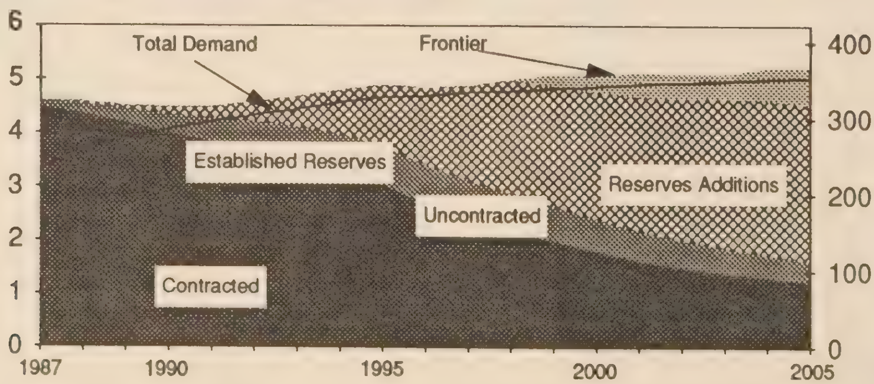


Low Case





High Case



Oil Supply

Established reserves of conventional crude oil in conventional areas are little changed from those shown in our last report.

Projected reserves additions of conventional crude oil (light and heavy) total 554 million cubic metres in the low case and 655 million in the high over the outlook period. These are higher than we projected in the 1986 report as a result of our current higher estimates of technical potential and more rapid resource development. About two-thirds of the reserves additions are expected to result from new discoveries and appreciation of currently established reserves other than from enhanced recovery. Appreciation of currently established reserves from enhanced recovery is expected to contribute the other one-third. As for natural gas, we assumed lower supply costs in the low case.

Total supply of crude oil and equivalent gradually declines in the low case, reaching a level in 2005 which is about three-quarters of the 1986 level, primarily because of a substantial decline in the supply of light crude, given the low world oil price in this case.

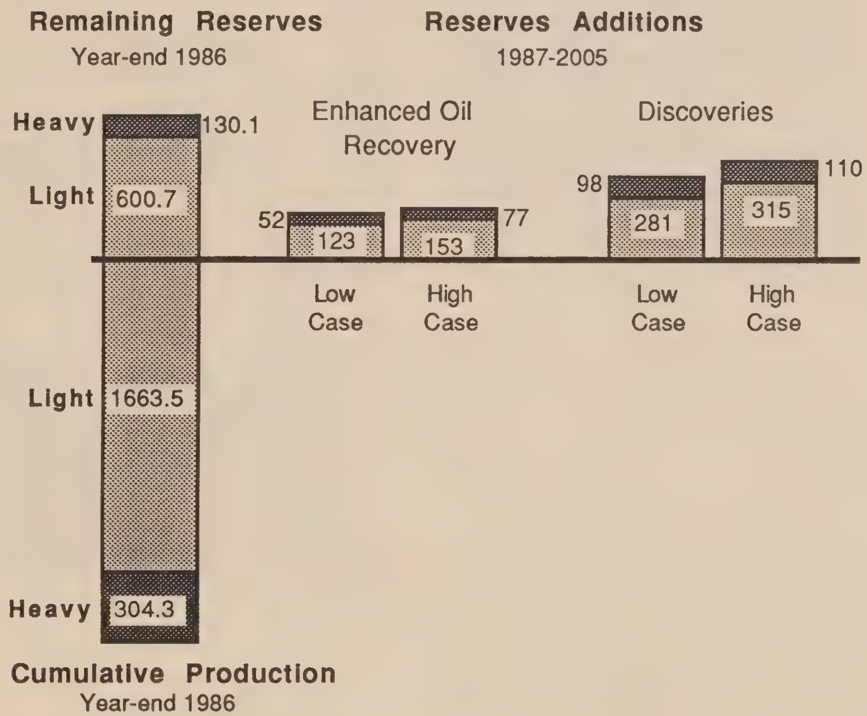
In the high case, total supply grows to a level about 15 percent higher in 2005 than its 1986 level. Light crude oil supply is relatively constant in this case; the growth in supply comes almost entirely from projected increases in heavy crude oil production based on bitumen development.

Considerable expansion of bitumen production and synthetic light crude oil production is feasible in the high case; but there are only very limited increases from current levels projected in the low case, most of which come from comple-

Figure 13

Reserves of Conventional Crude Oil Conventional Areas

Millions of Cubic Metres



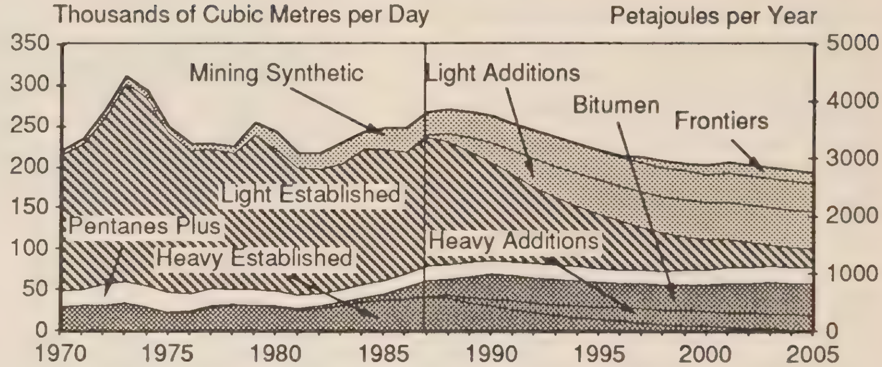
tion of projects already underway or reasonably certain to go ahead. In the low case we include no additional upgraders after completion of the Bi-Provincial plant in the Lloydminster area and no new integrated mining plants. In the high case we include three additional integrated mining plants, and the construction of another upgrading plant after the Bi-Provincial plant.

The extent to which synthetic light crude is produced by upgrading heavy crude oil depends upon whether the cost of the upgrading can be recovered by the differential between the bitumen price and the price of light crude oil. This relationship is very uncertain and difficult to assess. This in turn may mean that production of synthetic light crude from integrated mining is more likely, as its economic viability does not depend upon light-heavy oil price differentials.

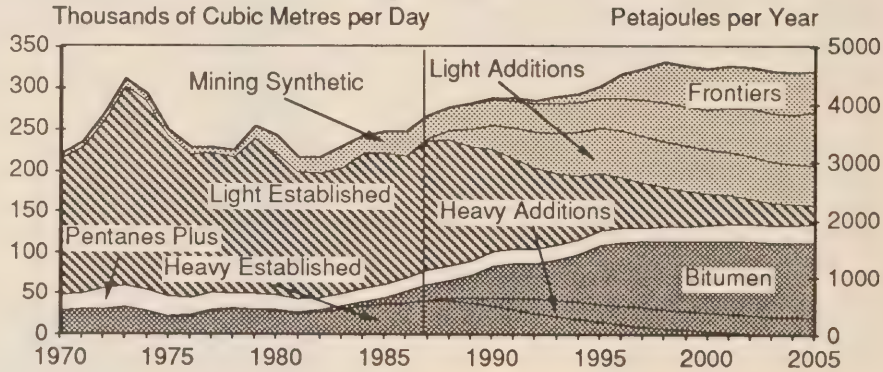
As a consequence we have included more synthetic light production from integrated mining plants than from heavy crude oil production and subsequent upgrading. We recognize the uncertainties associated with this judgement, and that a plausible scenario could have been constructed in which production of synthetic light from heavy crude upgrading was greater than from integrated mining operations.

Figure 14

Supply of Domestic Crude Oil and Equivalent Low Case



Supply of Domestic Crude Oil and Equivalent High Case



Frontier development included in the low case is restricted to production from floating platform systems on the Grand Banks and Scotian Shelf areas; in the high case, a fixed platform Hibernia development on the Grand Banks and the Amauligak development in the Beaufort Sea also proceed, Hibernia coming on stream in 1995 and Amauligak beginning with tanker shipments in 1990, followed by pipeline shipments in 1997. Total frontier production reaches 13 000 cubic metres per day in 2005 in the low case and 48 000 cubic metres per day in the high.

Our assessment of prospective oil supply does not reflect any particular fiscal or financial regime or measures of government support. Nor have our analyses taken account of particular corporate tax positions. With government support, more projects could show commercial viability than are included in our low case.

Electricity Supply

Domestic electricity demand, taking account of conservation and of demand management programs in B.C., Ontario and Quebec, grows from 423 terawatt hours in 1986 to 640 and 575 terawatt hours by 2005 in the high and low cases respectively, representing average annual growth of 2.2 percent in the high case and 1.6 percent in the low.

In addition to the low and high cases, we also developed an alternative scenario for electricity supply based on a higher level of interprovincial trade, consisting mainly of increased hydroelectric sales from Quebec to neighbouring provinces. The alternative scenario also includes more exports to the U.S.

Over the study period, generating capacity increases by 28 percent in the low case, 42 percent in the high, and 47 percent in the alternative case. The need for new facilities to meet domestic and firm export demand implies a substantial construction program. The provincial distribution of capacity additions is quite different in the alternative scenario.

Table 6

GENERATING CAPACITY BY REGION

MEGAWATTS

		INCREASE 1986-2005		
	1986	**LOW CASE**	**HIGH CASE**	**ALT. CASE**
ATLANTIC	12800	1800	4900	6700
QUEBEC	31800	10400	15000	18400
ONTARIO	25700	8000	10800	8600
PRAIRIES	15100	4400	6900	7600
B.C. AND TERR.	12900	2800	3900	4800
CANADA	**98300**	**27400**	**41500**	**46100**

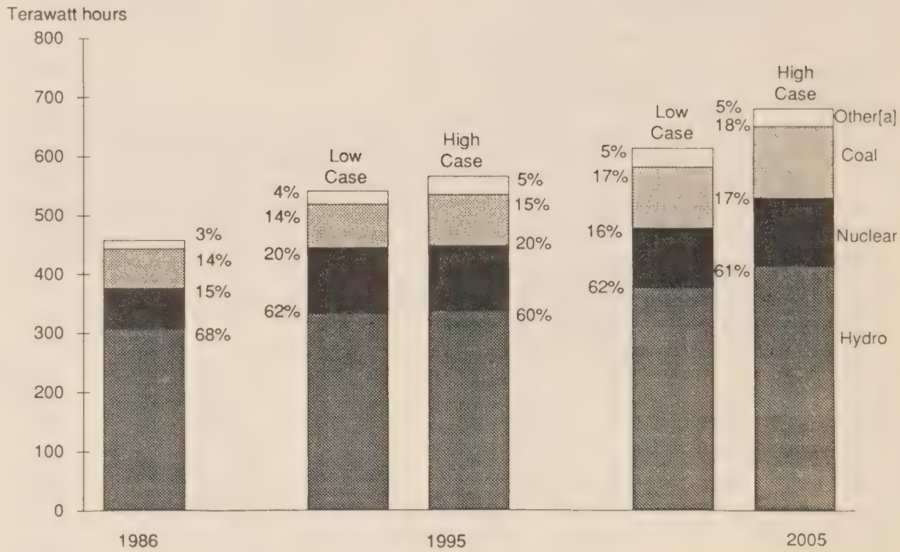
Hydro remains the dominant source of electricity production, although it declines slowly in importance relative to nuclear and coal. Non-utility generation is expected to remain relatively minor, contributing about 10 percent of the total in 2005.

Beyond the completion of Darlington there are three new nuclear plants in Ontario in the high case; in the low case they are not needed because demand grows more slowly, and in the alternative case they are not needed during the outlook period because Ontario purchases more electricity from Quebec.

The greater extent of interprovincial trade and higher exports in the alternative case require more aggressive development of electrical generating capacity in Quebec in this case as compared to that in the low and high cases.

Figure 15

Production of Electricity



Note: [a] Includes mainly oil and natural gas.

Coal Supply

Remaining recoverable reserves of coal total 6578 megatonnes, of which 71 percent consists of thermal coal, and the remainder, metallurgical coal. These reserves represent more than 100 times Canada's 1987 production of 61 megatonnes.

In the low case world economic growth is weak and prices of competing energy are low. As a consequence both domestic demand and export growth are modest. In this case production grows from 61 megatonnes in 1987 to 77 megatonnes in 2005.

The high case portrays a more buoyant environment for Canadian coal. Both domestic and export demand grow considerably, resulting in more rapid growth in Canadian production than in the low case. Production grows to 102 megatonnes by 2005.

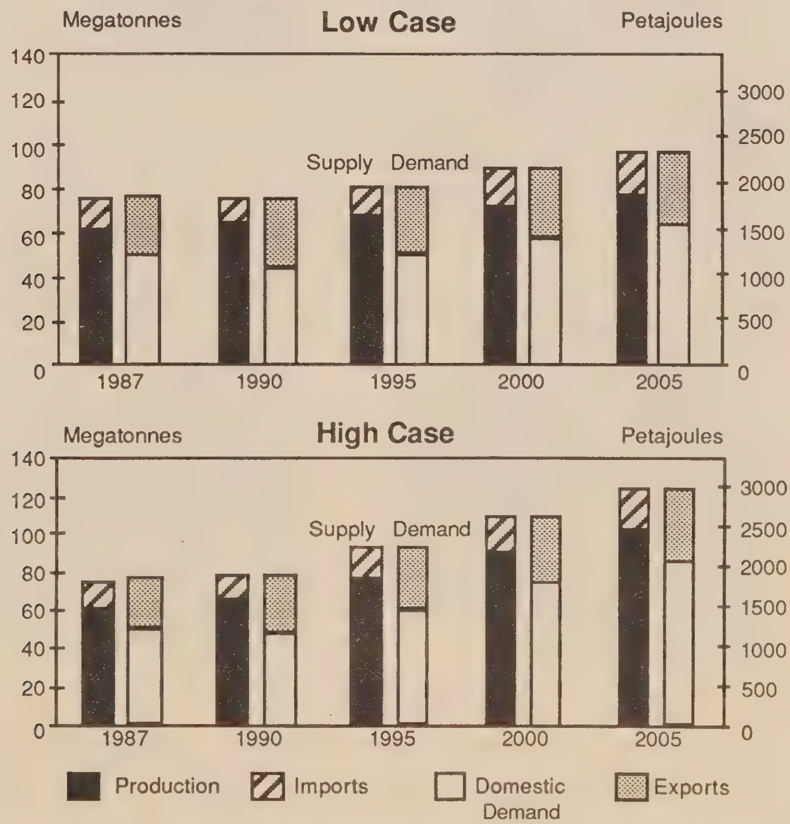
Table 7

Remaining Recoverable Reserves of Coal in Canada by Class at 31 December 1985

Class	Megatonnes	Petajoules
Lignitic	2236	30600
Subbituminous	871	15800
Bituminous		
Thermal	1553	36114
Metallurgical	1918	47186
Total	6578	129700
Thermal[a]	4660	82514
Metallurgical	1918	47186

Note: [a] Thermal includes all lignitic, subbituminous and thermal bituminous reserves.

Figure 16
Coal Supply and Demand in Canada



Concluding Comments

Notwithstanding the inherent uncertainties associated with an exercise of this kind, our results suggest a number of plausible conclusions about Canada's energy future.

- Our projected growth of **end use energy demand** in Canada is considerably less than the rate of economic growth with which it is associated. This is due mainly to our judgement that because of technological change, the ongoing replacement of capital goods, and current consumer attitudes toward energy consumption, demand growth will be modest even if energy prices were to grow at relatively low rates.

  The shares of different fuels in energy demand do not change dramatically from their present levels in either of our cases. The shares of both natural gas and electricity increase slightly at the expense of oil products and of alternative energy forms.

- **Energy exports** are a large component of total energy production in Canada and an important export industry. We expect this to continue over the study period.

- Our projections of **western Canadian natural gas and conventional oil supply** are both higher than in 1986 because of higher estimates of resources and their more rapid development. These higher resource estimates imply higher reserves additions per unit of drilling effort and lower unit supply costs.

- A continuing low oil price environment would be a very difficult one for the natural gas industry. Failing some accommodation, either in the form of lower costs of exploration and production or of continued streaming of gas prices to different classes of consumers or both, the size of the market for Canadian gas could decline considerably in such an environment.

- We have included gas supply from the Mackenzie Delta in both cases and from the Venture project only in the high case. In our 1986 report we showed only an illustration of frontier supply.

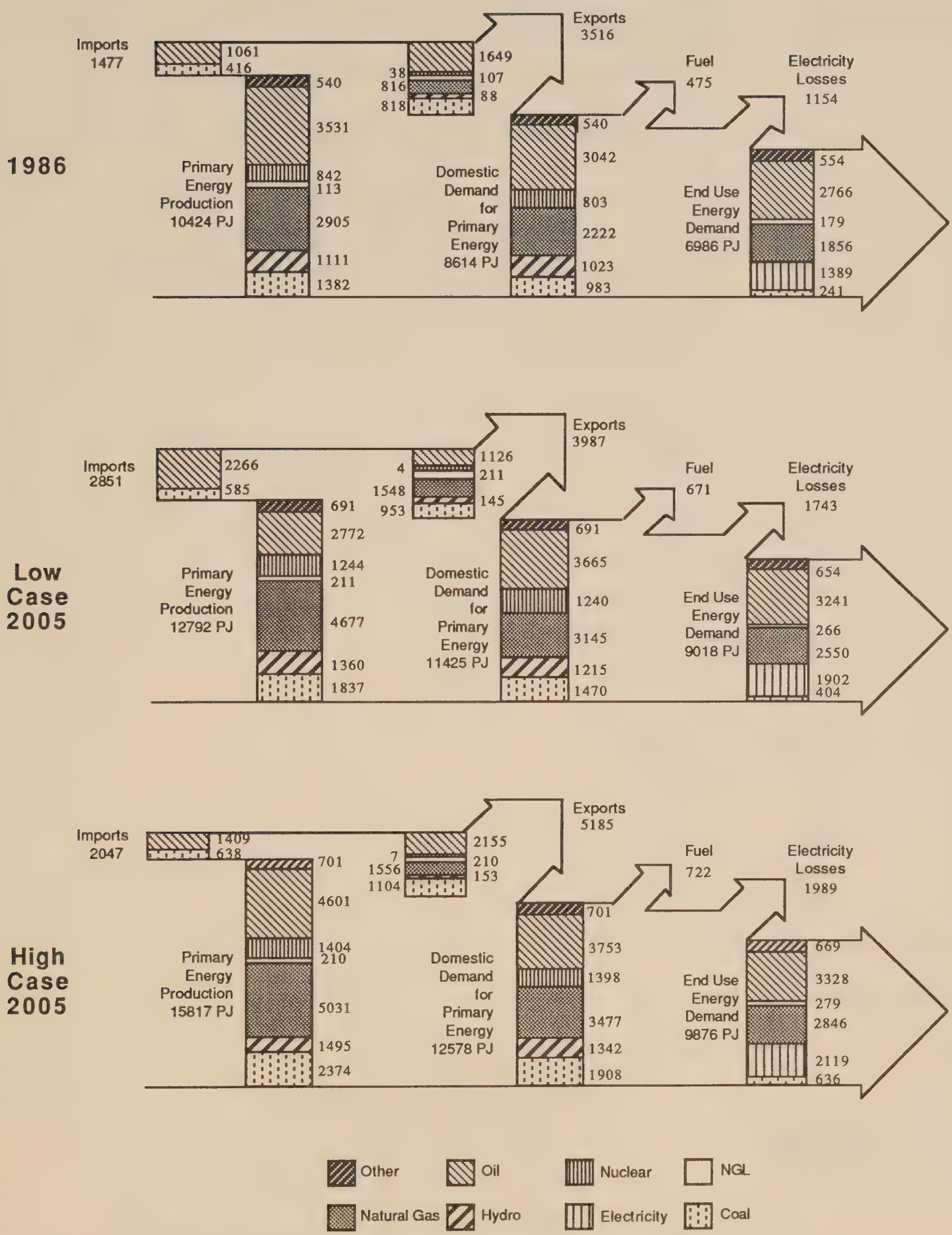
- In the high case we are more optimistic about **frontier oil** production in this report than we were in 1986. We are projecting higher production levels in the Mackenzie-Beaufort area, and some production from oil pools, other than Hibernia, off the east coast which we had not included in our 1986 estimates.

- Electricity supply planning has changed considerably in recent years in response to public opposition to the main power generation technologies because of concern over environmental impacts or about safety of nuclear plants. Utilities are increasingly looking to new sources of supply, the use of private power producers to supplement their generation capacity, and the use of incentives to encourage users of electricity to reduce demand. Nonetheless, our results suggest there will have to be large additions of conventional capacity to meet future requirements. It would require very different approaches to electricity pricing and supply policy for this conclusion to change.

We have conducted our analysis of Canada's energy requirements, of exports and of the supply of energy in Canada on the assumption that the existing framework of institutional practices and public policies will continue over our study period. However, there is increasing concern in Canada and elsewhere that present patterns of energy use may not be compatible with tolerable environmental quality, for example because of the implications of the "greenhouse effect". This has led to increased questioning of existing policies and practices and to demands for changes in institutional practices and public policies to encourage energy conservation and greater use of renewable, more environmentally benign, sources of energy.

Our study was not intended to determine the content of such a new set of policies, much less to assess their implications. However, the energy future for Canada portrayed in this report is by no means immutable. It represents our view of how that future might plausibly evolve allowing for two alternative paths of world economic and oil price growth. But underlying that analysis is the fundamental premise that our energy business is conducted in the future much as it has been in the past - a premise which is increasingly in question.

Figure 17
Energy Flows



Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h and nuclear electricity converted to PJ using 12.1 PJ/TW.h

Abbreviations of Names, Terms and Units

"NEB" or "the Board"	National Energy Board
Act	The National Energy Board Act
October 1986 Report	*Canadian Energy Supply and Demand 1985-2005* Summary and Detailed Reports, NEB, October, 1986
High Case	See Introduction. Based on assumption of high economic growth and high world oil prices.
Low Case	See Introduction. Based on assumption of low economic growth and low world oil prices.
OPEC	Organization of Petroleum Exporting Countries
OECD	Organization for Economic Cooperation and Development
NGL	Natural Gas Liquids (ethane, propane, butanes and pentanes plus)
$ C	Canadian dollars
$ US	United States dollars
J	joule
PJ	petajoule
EJ	exajoule
kW	kilowatt
MW	megawatt
GW	gigawatt
kW.h	kilowatt hour
MW.h	megawatt hour
GW.h	gigawatt hour

Prefixes

Prefix	***Multiple***	***Symbol***
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

1 petajoule = 10^{15} joules

Approximate Conversion Factors

1 cubic metre	contains	6.3 barrels
		35.3 cubic feet
1 petajoule	"	950 billion British thermal units (Btu)
1 cubic metre of natural gas	"	38 megajoules of energy
1 petajoule of natural gas	"	0.95 billion cubic feet (bcf)
1 cubic metre of crude oil	"	38 gigajoules of energy
1 kilowatt hour of electricity	"	3.6 megajoules of energy
1 tonne of coal	"	24 gigajoules of energy

Canada

6015